



## Risk Implications of Energy Policy Instruments

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# Risk Implications of Energy Policy Instruments



**PhD thesis 14.2014**

**DTU Management Engineering**

Lena Kitzing  
May 2014

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# Summary (English)

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In many countries in Europe and the rest of the world, electricity systems are on the verge of a new era: they are transforming from being CO<sub>2</sub>-intensive and centralised towards becoming sustainable and more integrated. The role of policy makers in this transition is evident: ambitious targets of abandoning the use of fossil fuels and of increasing the use of renewable energy sources (RES) need to become reality through respective investments in new technologies. Understanding the effects of energy policy and support instruments on investments, especially in terms of risks, is crucial for developing an adequate policy framework in energy systems with high shares of renewable energies. This dissertation contributes to the research area of RES policy support. With a special focus on risk implications of policy, the economic consequences of different RES support instruments are investigated, both from an investor's perspective and from a societal point of view.

This dissertation assesses energy policy and especially renewable support instruments with regard to their differences in investment incentives, effectiveness of deploying renewable technologies, cost-efficiency (in terms of required support levels) and welfare economic effects. Focus lies on policy incentives for electricity generation from renewable energies that have significant influence on the risk profile of investments (such as renewable quota systems and fixed feed-in tariffs). The consequences of different policy portfolios are evaluated. We show, both qualitatively and quantitatively, that policy makers cannot neglect risk implications when designing RES support instruments without compromising either on effectiveness or cost-efficiency of energy policy.

The central research questions are: how can risk implications of RES policy instruments be integrated into policy design, so that the policies provide adequate investment incentives? And can the consideration of such risk implications in policy design make overall energy policy more successful? These questions are answered in seven research papers (four journal papers, two conference papers and a working paper), based on a combination of micro-economic and policy analysis.

Financial theory is used for the quantitative analysis of investment problems under uncertainty, including mean-variance portfolio theory, real option analysis, Monte Carlo simulations and time series analysis of the underlying data. Modelling of

stochastic price processes plays an important role in the analysis. Using concrete cases for offshore wind in Denmark and Germany, we show that feed-in premiums structurally require higher support levels than feed-in tariffs due to the higher risk exposure. We quantify this effect for several cases, and obtain differences of 4.3-10 EUR/MWh, corresponding to up to 40% of the support payments in particular cases. Lower risk exposure under feed-in tariffs also leads to faster deployment and in some situations smaller project sizes. The results for tradable green certificate schemes are more ambiguous, depending on the characteristics of the underlying stochastic processes. We also show that policies that reduce risk for investors can trigger more successful energy transitions, if certain conditions are fulfilled and policy safeguards are put in place for later phases of the development.

Overall, this dissertation contributes with model development in the area of support scheme analysis, using several innovative approaches for partial models that produce easily and quickly applicable results. Thus, tools are provided that help in the design of RES support policies, e.g. when deciding between support instruments and when determining adequate support levels.

# Summary (Danish)

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I mange lande i Europa og resten af verden står el-systemer ved overgangen til en ny æra: De omdannes fra at være centraliseret og baseret på fossile brændsler til at blive bæredygtige og mere integreret. Politiske beslutningstagere har en vigtig rolle i denne process: Ambitiøse mål for at øge andelen af vedvarende energikilder skal realiseres gennem tilsvarende investeringer i nye teknologier. Forståelsen for energipolitikens virkning samt effekten af støtteinstrumenter på investeringer, især med henblik på risiko, er af helt afgørende betydning for udviklingen af hensigtsmæssige politiske rammebetingelser til energisystemer med en høj andel af vedvarende energikilder. Denne afhandling bidrager til forskningen på området om politisk støtte til vedvarende energi. Med særlig fokus på investeringsrisiko, undersøges forskellige støtteinstrumenters økonomiske konsekvenser, både fra et investorsynspunkt og fra et samfundsmæssigt perspektiv.

Afhandlingen evaluerer energipolitik og især støtteinstrumenter til vedvarende energi med hensyn til forskellene i incitamentet til at investere, effektiviteten ved etablering af vedvarende teknologier, omkostningseffektiviteten (i form af de nødvendige støtteniveauer) og velfærds-økonomiske effekter. Fokus ligger på økonomiske incitamenter til elproduktion fra vedvarende energikilder, som har væsentlig indflydelse på risikoprofilen i investeringer (såsom kvoteordninger og faste tariffer). Konsekvenserne evalueres for forskellige politiske valgmuligheder. Vi viser, både kvalitativt og kvantitativt, at politiske beslutningstagere ikke kan negligere effekter fra risikoeksponering, når der bestemmes hvilke støtteinstrumenter der skal bruges, og hvordan de skal bruges uden at det går udover effektiviteten.

De centrale forskningsspørgsmål er: Hvordan kan risikoeksponering fra støtteinstrumenter integreres i energipolitikken, således at der ydes passende incitamenter til at investere i vedvarende energi? Og kan hensyntagen til konsekvenserne af disse risici føre til en overordnet mere succesfuld energipolitik? Disse spørgsmål bliver besvaret i syv forskningsartikler (fire videnskabelige tidsskriftsartikler, to conferenceartikler og et arbejdsrapport), der er baseret på en kombination af mikroøkonomisk teori og analyse af virkemidler.

Der benyttes økonomisk teori til kvantitative analyser af investeringsmuligheder under usikkerhed, herunder portefølje-teori, realoptions-analyse, Monte-Carlo-simuleringer og tidsserieanalyse af de underliggende data. Modellering af stokastiske prisprocesser spiller en vigtig rolle i analysen. Vi viser at støttesystemer der bruger pristillæg, kræver, på grund af en højere risikoeksponering, strukturelt højere støtteniveauer end systemer der er baseret på faste tariffer. Vi kvantificerer forskellen i flere konkrete eksempler for offshore-vindenergi i Danmark og Tyskland og estimerer den til at være mellem 4,3-10 EUR/MWh, svarende til 40% af støtteomkostningerne i særlige tilfælde. Den lavere risikoeksponering ved faste tariffer fører også til hurtigere udbredelse af vedvarende energi og, i nogle tilfælde, mindre projektstørrelser. Resultaterne for kvoteordninger er mere tvetydige og afhænger af karakteristika i de underliggende stokastiske processer. Vi viser tilmed at en reduktion af risikoen for investorer kan hjælpe med til at få en succesfuld overgang til et bæredygtigt energisystem. Dette kræver dog at visse betingelser er opfyldt, og politiske sikkerhedsforanstaltninger bliver overholdt.

Samlet set bidrager denne afhandling til modeludvikling med henblik på analysen af støtteordninger og den relaterede risikoeksponering ved at bruge flere partielle modeller der er udviklet på en innovativ måde, og således nemt og hurtigt frembringer anvendelige resultater. Der er herved udviklet værktøjer som kan bruges af politiske beslutningstagere i processen om udvikling af ordninger til vedvarende energikilder, for eksempel når der skal vælges et støtteinstrument eller der skal fastlægges støtteniveauer.

# List of publications

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## Papers included in the PhD thesis

- Kitzing, L., Mitchell, C. and Morthorst, P.E., 2012, Renewable energy policies in Europe: Converging or diverging?, *Energy Policy* 51, 192-201.
- Kitzing, L., 2014, Risk implications of renewable support instruments: Comparative analysis of feed-in tariffs and premiums using a mean-variance approach, *Energy* 64, 495-505.
- Kitzing, L. and Ravn, H., 2013, Support mechanisms and risk: Implications on the Nordic electricity system. *10th International Conference on the European Energy Market (EEM 2013)*. IEEE Xplore.
- Kitzing, L. and Weber, C., 2014, Support mechanisms for renewables: How risk exposure influences investment incentives. *Working paper*.
- Kitzing, L. and Schröder, S.T., 2012, Regulating Future Offshore Grids: Economic Impact Analysis on Wind Parks and Transmission System Operators, *12th IAEE European Energy Conference, Venice*. Also published as: EUI Working Paper RSCAS 2012/65, European University Institute.
- Kitzing, L., Juul, N., Drud, M. and Boomsma T.K., 2014, A real options approach to analyse wind power investments under different support systems. *Paper submitted to journal*.
- Kitzing, L. and Mitchell, C., 2014, Achieving energy transitions: Reducing risk and creating an enabling environment. *Paper submitted to journal*.

## Peer-reviewed publications not included in the PhD thesis

- Andersen, F.M., Larsen, H.V., Kitzing, L., and Morthorst, P.E., 2014, Who gains from hourly time-of-use prices on electricity? - An analysis of consumption profiles for categories of Danish electricity customers, *WIREs Energy Environ* 2014, available online: doi 10.1002/wene.120.
- Klinge Jacobsen, H., Pade, L.-L., Schröder, S.T. and Kitzing, L., 2014, Cooperation Mechanisms To Achieve EU Renewable Targets, *Renewable Energy* 63, 345-352.
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Schröder, S.T., Kitzing, L., Jacobsen, H and Hansen, L.-L.P. 2011, Joint support schemes and efficient offshore investment: Market and transmission connection barriers and solutions. *EWEA OFFSHORE 2011, Amsterdam*. European Wind Energy Association.

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# Abbreviations

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<b>ARIMA</b>	Autoregressive integrated moving average: A model for stochastic processes.
<b>ARMA</b>	Autoregressive moving average: An approach to model stochastic processes.
<b>CAPM</b>	Capital asset pricing model: An approach to determine the cost of equity.
<b>CF</b>	Cash flows.
<b>DCF</b>	Discounted cash flow analysis: An approach to evaluate assets and firms.
<b>EC</b>	European Commission.
<b>EU</b>	European Union.
<b>FIN</b>	Financing support: A type of RES support instrument.
<b>FIP</b>	Feed-in premium: A type of RES support instrument.
<b>FIT</b>	Feed-in tariff: A type of RES support instrument.
<b>GARCH</b>	Generalised autoregressive conditional heteroscedasticity: An approach to model stochastic processes.
<b>GBM</b>	Geometric Brownian motion: A type of stochastic process.
<b>INV</b>	Investment grant: A type of RES support instrument.
<b>IRR</b>	Internal Rate of Return: A measure of project return.
<b>MLP</b>	Multi-level perspective: A framework to analyse transition processes.
<b>MVP</b>	Mean-variance approach.
<b>MS</b>	Member States of the European Union.
<b>NPV</b>	Net present value: A measure of project value.
<b>NSP</b>	Net present value of support payments.
<b>O&amp;M</b>	Operations and Maintenance cost.
<b>PSO</b>	Public service obligation: Fee used to finance support through consumer bills.
<b>RE</b>	Renewable energy.
<b>RES</b>	Renewable energy sources.
<b>RES-E</b>	Electricity production from renewable energy sources.
<b>RoA</b>	Return on Asset: A measure of return.
<b>R&amp;D</b>	Research and Development.
<b>SHV</b>	Shareholder Value.
<b>SS-model</b>	Schwartz-Smith model: An approach to model stochastic price processes.
<b>TAX</b>	Fiscal measures: A type of RES support instrument.
<b>TGC</b>	Tradable green certificates: A type of RES support instrument.
<b>TSO</b>	Transmission system operator.
<b>VaR</b>	Value-at-Risk: A risk measure.
<b>WACC</b>	Weighted average cost of capital.



# Part I: Risk Implications of Energy Policy Instruments

---

## 1 Introduction to the thesis

Electricity systems around the world are currently undergoing an important transformation, from being CO<sub>2</sub>-intensive and centralised towards becoming sustainable and more integrated within the overall energy system. In this, policy makers play an important role as they provide the investment incentives for making the transition become reality. As energy systems with high shares of renewable energies develop, also new challenges arise. Within this changing framework, understanding the effects of energy policy and support instruments on investments is crucial for developing efficient policies.

The aim of this dissertation is to assess certain aspects of energy policy for electricity production from renewable energies (RES-E). With a special focus on risk implications of policy, this dissertation investigates the economic consequences of different support instruments, especially with regard to differences in incentives for private investors, effectiveness of deploying renewable technologies, cost-efficiency (in terms of required support levels) and welfare economic effects. Focus lies on those policy instruments that have significant influence on the risk profile of investments, such as renewable quota systems and fixed tariffs. We show, both qualitatively and quantitatively, that policy makers cannot neglect risk implications when designing RES-E support policy instruments without compromising either on effectiveness or cost-efficiency of energy policy.

This dissertation focuses on analysing its major research question from different angles. For this, several different methodologies are applied. This is in contrast

to an approach in which one methodology is developed and applied to different problems. While the latter would have allowed a higher complexity of modelling and more detailed analysis, the approach taken here has the advantage of leading to solidly founded conclusions on a focused research interest.

## 1.1 Research interest

This dissertation aims at contributing to the understanding of the role of risk in policy making by generating new insights using economic policy analysis and quantitative methods from financial theory. It contributes to the debate about which type of policy instruments to apply in RES-E support, and how to apply them best.

The central research questions are:

**How can risk implications of RES-E policy instruments be integrated into policy design, so that the policies provide adequate investment incentives? And can the consideration of such risk implications in policy design make overall energy policy more successful?**

These research questions are answered in the following way: Paper A provides an overview of RES policy instruments and their application in Europe throughout the last decade. Papers B, C, D and F explore different approaches in quantifying risk implications of different policy instruments from a private investor's point of view and explore their effects on investment decisions and required support levels. Paper E adds an analysis on risk effects of different regulatory regimes. Paper G finally discusses the effectiveness and cost-efficiency of different risk exposures, including from a societal perspective, and draws conclusions on how they affect the successful transition to a sustainable energy system.

This dissertation shows that risk implications are an important factor to consider in policy design. One practical example could be e.g. that a country wishes to switch from one support scheme to another. Then, support levels have to be adjusted accordingly in order to uphold adequate investment incentives. This dissertation provides the tools necessary for such analysis and gives application examples based on concrete cases.

In several papers, we use offshore wind as a case example. This is due to the central role of offshore wind in the Danish and European energy strategies towards 2020 and beyond. Also, the offshore wind sector is dominated by large, professional investors, where risk implications are most often well considered in investment decisions. It has to be noted though that the results presented here may not be fully transferable to other renewables technologies, due to their sometimes different technical and systemic

characteristics and also different investor structure.

## 1.2 Research context

The focus of this dissertation lies on applied microeconomics and quantitative analyses of investment incentives in RES-E support schemes on the one hand, and qualitative policy analysis on the other. In the modelling of financial risk in investment decisions, this dissertation focuses on the interaction between investment incentives from the market and from RES-E support.

Making risk analysis for the electricity sector and its support mechanisms means dealing with a highly interdisciplinary problem that requires drawing on engineering, economics, financial theory, and policy analysis. Characteristics from all of these fields are highly relevant for the understanding of investment incentives for RES-E projects. These include e.g. technical project and infrastructure characteristics; the functioning of markets, risks and capital requirements; and the availability and functioning of policy options and their implementation opportunities.

As a general foundation, this dissertation thus uses literature from several fields. Economics, and in particular policy and energy economics, provides the basis for creating the relevant decision problems and for understanding the functioning of markets and their incentives. Related literature includes e.g. Alchian and Allen (1972), Cropper and Oates (1992), Jaffe et al. (2004), Just et al. (2004), Pindyck and Rubinfeld (2008), Simkins and Simkins (2013). Financial theory provides the understanding and the tools to model investment decisions. Related literature includes e.g. Markowitz (1952), Sharpe (1964), Black and Scholes (1973), Merton (1973), Arrow and Fisher (1974). Additional literature providing a basis for this dissertation includes Brealey and Myers (2003) and Koller et al. (2010) on corporate finance and valuation, Dixit and Pindyck (1994) on decision making under uncertainty, as well as Weber (2005), Burger et al. (2007) and Conejo et al. (2010) on risks in the energy system and related investments.

Particularly relevant for this dissertation is a body of interdisciplinary literature that deals with energy policy, comparative analysis of different policy instruments and related risks. Arrow and Lind (1970) have analysed the impacts of allocating risk between private and public investors. The role of risk in policy instrument choice has notably been analysed by Weitzman (1974) and subsequently by e.g. Fox (1990) and Menanteau et al. (2003). The work of Awerbuch (1993) using portfolio theory for determining optimal energy mixes has also sparked new interest in risk analysis for the energy system, e.g. in the analysis of fuel-mix diversification incentives by Roques et al. (2008). Mitchell et al. (2006) compare renewable obligations and a feed-in tariff, and conclude that risk reduction can enhance effectiveness of a policy

scheme. Butler and Neuhoff (2008) conclude for the case of wind power deployment that feed-in tariffs result in larger deployment at lower cost to consumers. Still, risk implications are not widely integrated in policy making, as Gross et al. (2010) demonstrate. The authors call for policy making that ‘looks beyond costs’. The implications of integrating risk more into energy policy making, has been discussed e.g. by De Jager and Rathmann (2008), De Jager et al. (2011) and Klessmann (2012).

Analysing the implications of risk requires the development of appropriate modelling tools that are fitted to the specific characteristics of the related investment decision problems. Rarely, quantitative approaches and tools are offered that allow the concrete analysis of risk implications for renewable energy technologies. De Jager et al. (2011) suggest an approach to adjust risk premiums according to different risk exposures from policy instruments. A somewhat more elaborate approach is taken by Yu et al. (2006), who first made an assessment of renewable policy instruments using real options for a new switchable tariff in Spain, and Boomsma et al. (2012), who have developed a real options approach to compare renewable support instruments including market risks and uncertainty stemming from policy making.

However, there is no substantial body of literature on quantitative analysis of risk implications for renewable support policies, and consequently no established opinion on what methodology and approach should best be adopted. This is another reason why this dissertation develops and compares different approaches.

Additionally, this dissertation draws on literature that has laid groundwork for analysing details of renewable support policies in Europe. This includes e.g. Ragwitz et al. (2007), Held et al. (2010) and Haas et al. (2011b). Other literature used includes legal and policy documents, as well as data provided by governments and other public bodies, for example the European Commission, Eurostat, the national governments of several European countries and other public authorities, such as the Danish Energy Agency.

Each paper in Part II of the thesis also includes a description of the research context and describes major literature specifically relevant for the respective analysis.

### **1.3 Structure of the thesis**

The thesis is structured into two parts. Part I introduces and summarises the research. It introduces the common research interest, describes the background of the research, discusses and compares the different methodologies applied, and summarises the results. Part II is a collection of publications including the following papers:

**Paper A** is a journal paper published in *Energy Policy*. It analyses renewable energy policies in Europe throughout the last decade and identifies trends in the implementation of different support instrument types.

**Paper B** is a journal paper published in *Energy*. It is a comparative analysis of feed-in tariffs and premiums using a mean-variance approach to quantify the differences in required support levels from different risk exposures.

**Paper C** is a peer-reviewed conference paper of the *10th International Conference on the European Energy Market (EEM)* and is published in *IEEE Xplore*. It enlarges the analysis of Paper B into an energy system analysis for the Nordic electricity system.

**Paper D** is a working paper. It as well comprises a comparative analysis of feed-in tariffs and premiums, using a cash flow approach including liquidity management (treating both systematic and unsystematic risk), and quantifies differences in required support levels.

**Paper E** is a conference paper of the *12th IAEE European Energy Conference* and is published as working paper in the *Loyola de Palacio Programme on Energy Policy* of the *European University Institute (EUI)*. It is an economic impact analysis on wind parks and transmission system operation for different options of regulating offshore grids. It determines differences in investment incentives under these options.

**Paper F** is a journal paper submitted to a scientific journal. It is a real options analysis on how support instruments can influence investment decisions. It optimises the investment problem in terms of investment timing and project size under a capacity constraint.

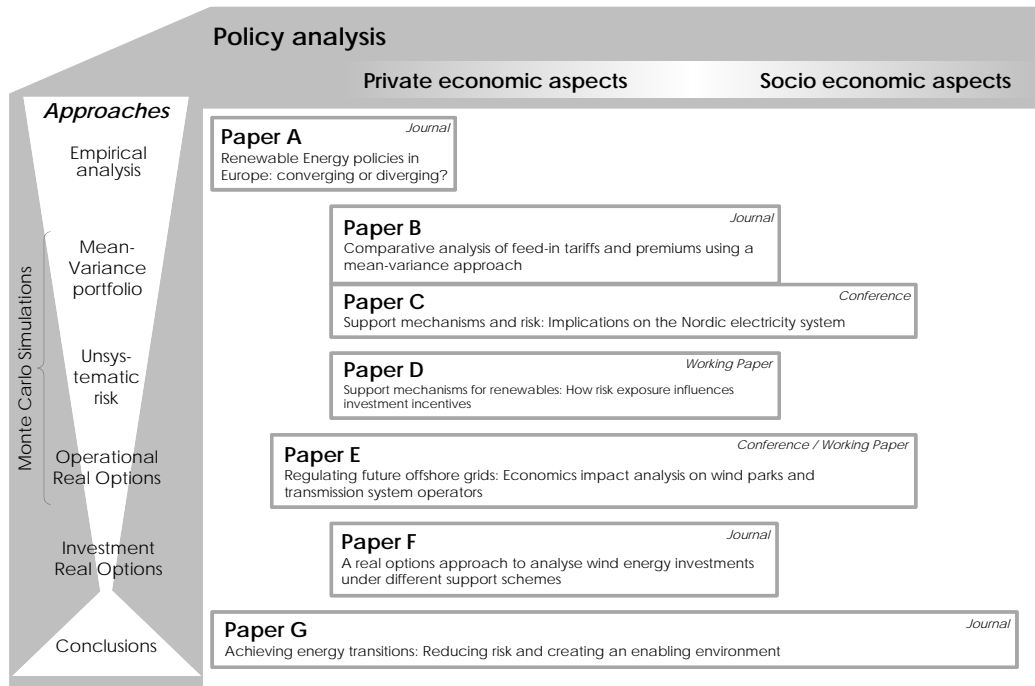
**Paper G** is a journal paper submitted to a scientific journal. It combines policy analysis with an economic perspective and explores how risk reduction from support instruments that stabilise income (such as feed-in tariffs) and creating an enabling environment (such as strategic development of related niches) can help to achieve successful energy transitions.

The papers and their results are summarised in more detail in Section 4.1.

The topical and methodological relations of the papers are illustrated in Figure 1. All papers deal with policy analysis, to a varying amount addressing private economic and socio-economic aspects. The approaches of the papers evolve from a rather high-level empirical analysis via more detailed mean-variance portfolio analysis into deeper microeconomic real options analysis. The concluding paper again adopts a broader perspective and sets the results of the preceding papers into perspective.

The remainder of Part I is structured as follows. Following this introduction, Section





**Figure 1:** Structure of the research

2 gives some essential background on electricity markets, energy policy and risks in the context of investment decisions and renewable energy support. Section 3 describes the methodologies and approaches applied in this dissertation. While the methodology can in most papers only be described in limited detail, this section gives a more comprehensive presentation, especially e.g. regarding the applied stochastic price processes and statistical tools. Section 4 presents and discusses the results of the papers and sets them into the context of the overall dissertation and its contribution to model development and policy analysis. Section 5 draws general conclusions from the results generated within this dissertation and adds an outlook on further research options.

## 2 Background: Electricity markets, policy and risks

### 2.1 Competitive electricity markets

Whereas the electricity sector had been considered a natural monopoly throughout most of the 20<sup>th</sup> century, there is now a rather broad understanding that (regulated) competition in electricity production and the retail business is favourable for the efficient operation and development of the system (Helm, 2007). In this disser-

tation, mostly the Nordic electricity market is used as reference. Here, trading is centred around NordPool, a multi-national power exchange including seven Northern European countries. The Nordic power market comprises of three sub-markets: (1) a financial market for trading of financial long-term futures contracts and financial derivatives (Power Nordic, run by NASDAQ OMX Commodities Europe), (2) a physical spot market for day-ahead trades ('Elspot'), and (3) an intraday (up to near real-time) market for the handling of deviations (imbalances) ('Elbas') (both run by NordPool Spot). This dissertation uses the day-ahead market as main reference for power sales and income for RES producers. NordPool Spot provides an hourly spot system price as well as 15 area prices based on day-ahead bids submitted to the pool (NordPoolSpot, 2014a). As of February 2014, the Nordic electricity market is tightly connected with Central Western and Southern Europe through price coupling and implicit allocation of cross-border transmission capacity, thus forming a common spot market covering approx. 75% of the European power market (NordPoolSpot, 2014b).

The scope of this dissertation is not electricity markets as a whole, but investment decisions on these markets. Markets are therefore only discussed very briefly. Electricity markets possess rather special physical and economic characteristics, some of which make policy intervention necessary (Pindyck and Rubinfeld, 2008). First, electricity is complementary to the rest of today's economy: The societal costs of scarcity (excess demand) are higher than those of excess supply (Helm, 2007). Second, storage options are extremely limited, so supply and demand must be kept balanced continuously. However, both supply and demand are highly fluctuating and stochastic, due to changes in temperature, weather, technical failures, etc. Helm (2007) argues that because of marginal pricing on markets and a societal preference to avoiding scarcity, the investment incentives that a free market would provide for private firms are lower than what would be optimal for society. Third, electricity supply requires a network, which is a shared pool, a public good to the system as a whole. At the same time, electricity markets are relatively decentralised, limited by e.g. interconnection bottlenecks. These characteristics constitute market failures that make regulation necessary. Additional market failures include negative environmental externalities, which are significant in electricity markets due to the high emissions of CO<sub>2</sub> and other pollutants. Furthermore, Gross et al. (2007) and Borenstein (2012) describe a number of non-environmental externalities, such as geopolitical and security of supply concerns, job creation, social and equity issues, technology development and innovation effects.

From an economic perspective, the need for policy intervention and regulation on electricity markets does not yet justify the use of dedicated support instruments for renewable energy technologies. In Paper G, we discuss that, according to the 'polluter-pays' principle, negative environmental externalities are often deemed best internalised by increasing cost of polluting units rather than by supporting non-polluters. However, because of the multitude of effects (including e.g. innovation externalities) and complex policy objectives (including e.g. security of supply con-

cerns and social issues) in electricity markets, support schemes can be the favourable option at least in the short to medium term (Kalkuhl et al., 2013). And that is the case even with an emission trading scheme present on the European market.

In this dissertation, we do not discuss or analyse the question if dedicated financial support for renewable technologies should be established. All European Member States (MS) do have such support schemes in place (Kitzing et al., 2012), and this is not expected to radically change in the foreseeable future. This dissertation therefore focuses on optimising the applied RES-E support schemes.

## 2.2 Energy policy in Denmark and Europe

In Denmark, no dedicated energy policy existed prior to 1973, where electricity was supplied by a regulated, publicly owned industry. Denmark was to more than 95% dependent on energy imports, and the oil crisis of 1973-74 lead to a rethinking of Danish energy policy (Lund, 2000). With focus on energy security and socio-economic concerns, first energy plans were prepared. In 1981, such a plan for the first time suggested the promotion of different technology alternatives. During the 1980s, renewable energy began to play a larger role in energy planning, and the first major support schemes were established. In 1990, climate change and a reduction of CO<sub>2</sub> emissions came into focus.

With the Electricity Supply Act (1999)<sup>1</sup> a liberalised, open market was established. This development was influenced by emerging activities related to energy policy on European level, where the European Commission, beginning with a first directive in 1996 (EC, 1996), required the stepwise opening of electricity markets to competition and the creation of an internal European market.

European energy policy has always been focused on creating “well functioning energy markets that ensure secure energy supplies at competitive prices” (EC, 2006). But also environmental and climate considerations play a role. In this, renewable energies are important. As Bechberger concluded in Morata and Sandoval (2012), European renewable energy policy should be seen as the only strategic option for rapidly reducing energy import dependency (and thus relieving security of supply concerns) as well as for reducing greenhouse gas emissions. With the Lisbon Treaty (TFEU; EU, 2007), energy has become a ‘shared competence’ between the EU and its Member States (Chapter 4, TFEU). However, the decision on the energy mix, usage of resources, and on taxation still remains with the Member States alone (‘energy sovereignty’) (Art. 194.2, TFEU). Nevertheless, the EU has been pushing renewable

<sup>1</sup>Elforsyningsloven no. 375, with later amendments, no. 151 (2003), no. 494-5 (2004), and latest by governmental order no. 1329 (2013)

energy deployment in all Member States, at first with White Papers (EC, 1995; EC, 1997), and non-binding targets (RES Directive 2001/77/EC; EC, 2001). In early 2009, the Climate and Energy package became law after intense inter-governmental negotiations (Morata and Sandoval, 2012, p.9). As part of the package, the Renewable Energies Directive (2009/28/EC; EC, 2009) established binding renewable targets for 2020 in all Member States. This implied the establishing of national support schemes, also in countries beyond the EU through cooperation in the Energy Community.

The above mentioned energy sovereignty of Member States in the current political framework includes sovereignty over renewable energy support. The influence from EU level is only indirect, e.g. through state aid rules. The latest state aid guidelines (coming into force in mid 2014) are indeed rather detailed on concrete options for renewable support instruments employable by Member States (EC, 2014). In the past, there have also been several concrete suggestions to change the political framework on sovereignty over RES support and it was planned to harmonise it (Rowlands, 2005). This has however never found the necessary unanimity amongst Member States (see Fouquet et al., 2012, for a discussion of RES support harmonisation and EU law). Still, there is a strong development towards Europeanisation of energy policy governance (see also Morata and Sandoval, 2012), aiming at facilitating the advancement towards policy coherence.

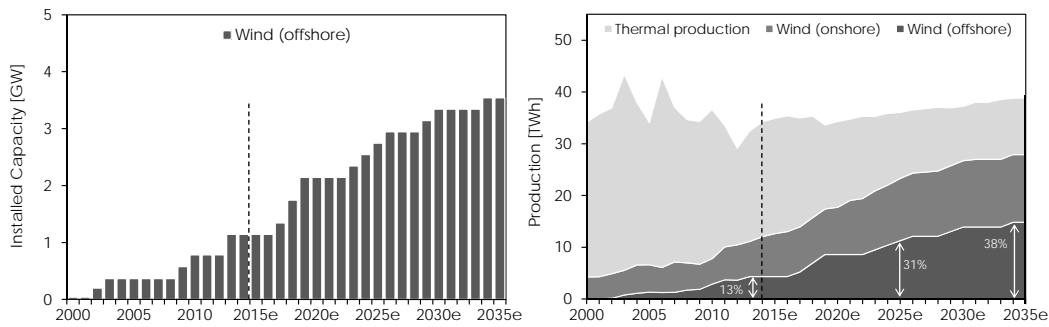
In Paper A, we have investigated if recent trends in renewable support policies show signs of convergence or divergence. We showed that national policy support schemes converge in the type of instruments chosen and the scope of application. We concluded that further analysis within this dissertation should rather deal with analysing national support schemes than with a pan-European option, as such an option will either become less controversial once best practices and decision tools have been developed, or even dispensable. This perspective is also supported by Busch and Jörgens (2012), who have analysed the proliferation of RES support instruments in Europe, based on three mechanisms: cooperation (multilateral agreements or supranational law, e.g. at EU level), coercion (forceful imposition of policies, or economic and political conditionality), and diffusion (policy information is communicated in the international system and then voluntarily and unilaterally adopted by states). The authors conclude that in the case of RES-E support policies, Europeanisation through mediated diffusion of national approaches is a strong mechanism that should be paid more attention in research and policy making.

### **Denmark's ambitious energy plan 2050**

Denmark's energy strategy is to become independent of fossil fuels by 2050, and to have a fossil-free electricity sector in 2035 (Danish Government, 2011). By the time of adoption in 2011, this ambitious plan was the first of its kind in the world. Key elements in the transition to a fossil-free Danish energy system are (1) a highly efficient energy consumption, (2) the electrification of heating, industry and transport,

(3) more electricity from wind power, (4) an efficient utilisation of biomass and biogas, RES-based district and individual heating, and (5) an intelligent energy system (Danish Government, 2011).

These ambitious targets require significant investment in renewable energy assets, especially in wind energy. Immediate initiatives include tenders for two large offshore wind parks and a number of smaller near-shore parks, totalling 1500 MW, and initiatives for onshore wind power, aiming at an additional 500 MW (KEBMIN, 2012). Also after 2020, much of the required investment is expected to be delivered by offshore wind (DEA, 2012; Energinet.dk, 2012). Offshore wind could potentially rise to deliver approximately 38% of electricity production in Denmark in 2035, as shown in Figure 2.



**Figure 2:** Installed capacities of offshore wind (left) and electricity production (right) in Denmark, data from 2000-2013 based on Energinet.dk (2014b) and LORC (2014), forecasts based on DEA (2012), Energinet.dk (2012) and own calculations

Thus, offshore wind is expected to be the largest growth sector for investments in energy production facilities in Denmark. In Europe and the world, the offshore wind sector is expected to reach 14 bnEUR and 130bnEUR of annual investments in 2020, respectively (Roland Berger, 2013). For this reason, this dissertation bases most case studies on offshore wind investments.

### 2.3 Support for renewable energies

In Section 2.1, it was mentioned that granting financial support for renewable energies can be beneficial and necessary even in liberalised energy markets. In fact, support for energy technologies has been a popular and readily used part of energy policy in many European countries for decades. Support instruments are used to set appropriate incentives for private actors to invest in the politically desired technologies. The effectiveness of these incentives determines if policy goals are met.

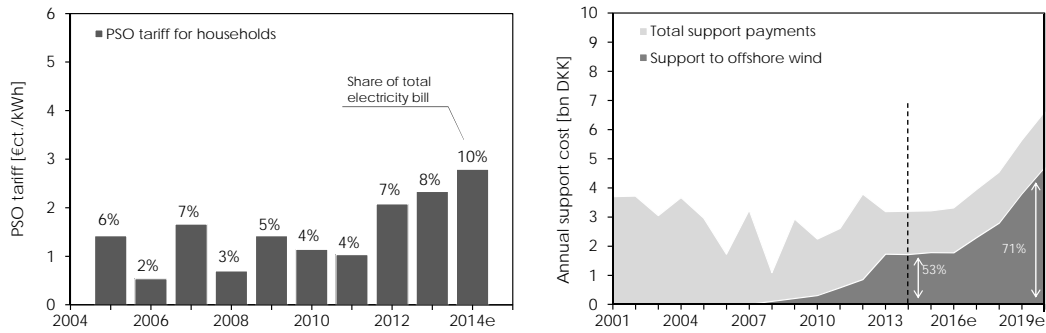
Zachmann et al. (2014) define three complementary strategies to replace fossil fuels by renewable energy: 1) support currently available renewable technologies until they are competitive; 2) make all undesired technologies uncompetitive by taxation or regulation; 3) support innovation in renewable technologies to reduce their cost in the future. In this, two innovation policies are interacting: supporting Research and Development (R&D) and encouraging ‘learning-by-doing’ through government-supported deployment (see Arrow, 1962). The IPCC (2011, p.889) describes technology development and market deployment as two mutually reinforcing cycles that together drive down technology costs.

Until the 1990s, support for renewable energies in Europe focused much on R&D (Klessmann, 2012). However, market uptake was slow, amongst other things because of economic and market barriers, administrative and legal barriers as well as grid related barriers (Klessmann, 2012). Focus shifted more and more towards support of deployment, i.e. the introduction of the technologies into the market. Today, the budget for support of deployment is of two magnitudes larger than that for support of R&D: In the five largest EU countries plus the Czech Republic, support of deployment amounted to 48,298 million EUR in 2010, whereas R&D expenditure only reached 315 million EUR (Zachmann et al., 2014).

In some countries, supporting the deployment of RES-E was highly effective, and significant increases in the shares of new RES-E in the electricity mix could be achieved. In Europe, the average share of renewables in gross electricity consumption has increased from 12.2% in 1990 to 23.5% in 2012, with some of the highest shares observable in the Scandinavian countries (Norway: 104.3%, Sweden: 60.0%, Denmark: 38.7%, Finland: 29.5%) (Eurostat, 2014).

The higher the shares of financially supported RES-E production become, the more significant becomes the effect of support costs on electricity consumers and tax payers. Del Río and Cerdá (2014) describe when and how RES-E support cost may become of concern for society. In practice, discussions about the burden of RES-E support have already arisen (e.g. in Germany and the UK; see Lauber and Jacobsson, 2013; Auverlot et al., 2014). In Denmark, the PSO fee (through which the financing for RES support is obtained), is expected to reach 10% of an average household electricity bill in 2014 (Energinet.dk, 2014a; and own calculations). Figure 3 illustrates the past development of the PSO fee as well as the past and expected development of total support cost in Denmark.

The cost of RES-E support are in Denmark and the rest of Europe expected to rise until 2020 and beyond, as ambitious renewables targets shall be reached (see also IHS CERA, 2014). The expected substantial development of offshore wind energy in Denmark could lead to a situation in which already in 2020, more than 70% of total support payments are dedicated to this technology (DØRS, 2014; and own calculations). With the total support payments then rising to an unprecedented



**Figure 3:** PSO fee for an average household (left) and total support payments (right) in Denmark, data from 2001-2014 based on DØRS (2014) and annual reports from Energinet.dk, forecasts based on DØRS (2014) and own calculations

level, the PSO fee will also further increase.

In light of the expected increase of support cost, it is of utmost importance to optimise support schemes and energy policy as a whole, not least in order to ensure public acceptance for the necessary transition to a sustainable energy system. The cost of the energy transition should in fact be seen as an investment that is expected to deliver significant benefits in the future. But it can only be undertaken with sufficient backing by society. Partly, the burden on today's consumers can be mitigated by improving the design of support schemes, so that the consumers' money is put to the best use in delivering the desired policy goals. This dissertation contributes to the important task of optimising the design of RES-E support schemes.

### 2.3.1 Evaluation of RES policy instruments

The optimisation of support schemes is complicated by the fact that there is no common evaluation rule or set of success criteria for support instruments. In fact, there exist very different understandings of the two most important evaluation criteria for policy instruments: effectiveness and cost-efficiency. Del Río and Cerdá (2014) discuss this illustratively.

**Effectiveness** is generally defined as the ability of a policy (or a policy package) to deliver the desired outcome at the desired time. But what is the desired outcome of a RES policy? Two of the most usual definitions are: (1) maximum possible RES deployment is desired. In this case, RES targets for specific years (e.g. 20% in 2020) are set or perceived as minimum levels. This corresponds to the definition of the European Commission (EC, 2008) and current RES target setting in many countries (see also Haas et al., 2011a). Alternatively, (2) only deployment up to a certain limit is desired for a defined period. In this case, RES deployment targets are

set as fixed (maximum) levels. This is generally accompanied by an overall budget limit for support. The latter understanding of effectiveness often occurs in situations where policy objectives other than RES deployment become dominant (e.g. related to system integration or controlling customer burden). We discuss in Paper G that fast deployment is crucial in the early phase of a transition to a sustainable energy system, whereas more complex policy goals and integration issues often cause a shift in the understanding of effectiveness during later stages of the transition.

**Cost-efficiency** of a support policy is tightly related to welfare economic considerations. In classical economic view, only those outcomes are efficient that maximise social welfare (the sum of producers' surplus and consumers' surplus). This inherently demands that only the cheapest of different technologies and projects should be chosen until the desired deployment level is reached. Therefore, economists often favour policy instruments that adhere to the equi-marginal principle. These are mostly technology-neutral, competitive instruments that can ensure the minimisation of overall generation cost. Two issues should, however, be noted: First, this static perspective on efficiency does not take dynamic effects into account. But technologies that are expensive today might, through the mutually reinforcing cycles of deployment and technology improvements, become the favourable option over the long run. This can however only be realised when additional costs are accepted today (Finon and Menanteau, 2004). Second, this narrow definition of efficiency leaves limited room for more complex policy goals, such as domestic industry development, job creation, and controlling consumer burden. We discuss this further in Paper G. With such a broadened perspective, the minimisation of overall generation cost can no longer be the single objective. In fact, the European Commission uses an efficiency indicator that does not only consider the cost of the supported technologies but that compares the level of support to the generation cost: "The closer the level of support is to the generation cost, the more efficient a support mechanism is in terms of covering the actual costs" (EC, 2008, p.9).

This dissertation adopts a rather broad perspective on both effectiveness and cost-efficiency. As starting point of the analysis, it is assumed that there exists a set of pre-defined policy goals, which might be technology-neutral or technology-specific. Whatever the actual policy goals are, the chosen support policies can be improved by tailoring them optimally to the specific investment incentive they should give.

Too low support levels would lead to underinvestment and thus failure to reach deployment targets. This is ineffective in either definition. Too high support levels would allow investors to accrue windfall profits which are paid for by consumers and it would potentially lead to RES-E deployment 'booms'. Neither of these effects may be desired, depending on the definition of both effectiveness and cost-efficiency. This dissertation provides a better understanding of the investment incentives and the role of risk in support policies. This leads to an ability of better tailoring support schemes to policy goals and of determining the support levels more exactly, so that both too



high and too low levels can be avoided. In this sense, this dissertation contributes to improving support policies in terms of effectiveness and cost-efficiency.

### 2.3.2 RES policy instruments in Europe

As described in Section 2.2, EU Member States are responsible for their national RES support policies. The policy instruments available for supporting RES deployment can be broadly categorised into seven policy types, as illustrated in Table 1.

**Table 1:** Types of RES support policies as applied in Europe (Kitzing et al., 2012)

<b>Major support instruments</b>
Feed-in tariffs (FIT)
Feed-in premiums (FIP)
Tenders (TND)
Quota obligations with tradable green certificates (TGC)
<b>Supplementary support instruments</b>
Investment grants (INV)
Fiscal measures (TAX)
Financing support (FIN)

In the following, the different policy types are shortly described. A more detailed description including implementation examples is given in Paper A.

**Feed-in tariff (FIT)** schemes provide guaranteed prices to eligible producers. Feed-in tariffs are the dominant RES support policy instrument in Europe, currently applied in 21 EU Member States. Often, FIT schemes exempt producers from market participation - an entity (often the transmission or distribution system operator) is obliged to off-take the electricity at the guaranteed price, market the electricity and pass on the costs of the scheme e.g. to electricity consumers via public service obligation (PSO) fees added to the electricity bill. More recently, guaranteed prices are granted as variable add-ons to the market price (sliding premiums). Here, the FIT is paid out as the difference between the guaranteed price and the market price.

**Feed-in premiums (FIP)** are guaranteed premiums paid out as a fixed add-on to the market price. Generally, a producer of renewable electricity receives a premium per unit (MWh) in addition to the proceeds of selling the power on the power markets. Currently, seven Member States apply feed-in premiums for RES-E support.

**Tenders (TND)** (or auctions) are typically used in combination with another policy type. In a tendering process, the responsible authority launches calls with defined amounts of capacities, often for specific projects (or groups of projects). Potential

investors then compete for winning the opportunity to develop their project, and bid for the required support level and (potentially) other specifications. Tenders are recently much in focus on European level (EC, 2014). Several European countries have experience with tenders for investment grants and tenders for guaranteed prices.

**Quota obligations with Tradable Green Certificates (TGC)**, also called Renewable Portfolio Standards (RPS) with Renewable Energy Certificates. In TGC schemes, either producers or suppliers of energy are obliged to have a specific share of renewables in their portfolio (the quota obligation). Thus, in contrast to FIT and FIP, where price levels are controlled by the policy makers, TGC are referred to as ‘quantity’-control instrument. Certificates that represent a certain production from renewables can be freely traded on a market and a market price materialises for the certificates in each compliance period (e.g. one year). TGC schemes can be uniform (all technologies receive the same amount of certificates per generated unit of electricity) or differentiated (certain technologies receive more certificates per generated unit than others), the latter is called ‘banding’. In some applications, certificates can be transferred from one compliance period to the next, they are ‘bankable’. Note that these certificates are to be distinguished from voluntary green certificates of the type ‘guarantee of origin’, for which no quota obligation or penalty of non-compliance is established. Currently, six EU Member States apply TGC schemes.

**Investment Grants (INV)** are financial supports granted by governmental (and European) institutions to investors in renewable energy projects in the form of non-reimbursable payments. Most investment grants are paid out at time of construction, so the amount of RES-E being generated from a project is not directly targeted. Most European countries have implemented investment grant schemes for RES-E, ranging from 5% to more than 70% of the total investment cost.

**Fiscal measures (TAX)** are here defined as direct fiscal support. Indirect tax incentives, such as eco-taxes on fossil fuels or CO<sub>2</sub>-taxes, are not specifically considered as support instrument here, assuming that they are implemented solely to internalise external cost. Direct fiscal support measures include income tax relief, electricity tax relief, reduced value added tax (VAT), and net metering for own consumption.

**Financing support (FIN)** contains a range of support instruments in the financing area, also defined as ‘financial engineering instruments’, targeting the area of repayable investments (in contrast to non-reimbursable grants), designed for helping investors of renewable projects to access the capital market and to obtain financing at adequate terms. They include reimbursable equity investments or provisions of venture capital by governmental institutions as well as debt financing, e.g. in form of low-interest loans by a governmental financial institution. More recently introduced instruments are Mezzanine finance (equity/debt hybrids), equity guarantees, loan guarantees and securisation products (e.g. provision of credit default swaps).

From our historic analysis of support schemes in European Member States throughout the last decade in Paper A, we find that national RES-E policy strategies are rapidly changing. In Paper G, we argue that changes in policy can be necessary to adapt to the requirements of the phase an energy transition currently is in. A natural development in an energy transition can be to progressively expose investors of RES-E projects to more market risks. The choice of support instrument has a profound influence on such risk exposure. Since recently, the European Commission and the European Member States focus more and more on system and market integration, and new guidances on RES support suggest moving towards instruments that expose investors to more market risk (EC, 2013; EC, 2014). This could include switching from a FIT to a FIP or a TGC, and also introducing more competitive elements in existing schemes. Currently, the majority of EU Member States applies FIT (21 countries), whereas only seven and six Member States use FIP and TGC, respectively. FIP schemes have experienced one of the highest growth rates during the last years. Only recently, FIP schemes have surpassed TGC schemes in terms of application by country. There is thus an urgent need for analysis on the effects of switching from one instrument to another, especially from FIT to FIP.

## 2.4 Uncertainty and risk

Almost all investment decisions taken in real life are complicated by the fact that the future is not certain, i.e. there is a possibility that an outcome will be different than expected. Stirling (1994) differentiates between three states of incertitude: risk, uncertainty and ignorance. All three states are rooted in (1) lack of perfect information (outcomes are not certain), and (2) exposure to financial loss or gain related to the uncertain outcome. It is the level of incertitude that differentiates the three states: When dealing with risk, “a probability density function may meaningfully be defined for a range of possible outcomes”; when dealing with uncertainty, “there exists no basis for the assignment of probabilities”; and in case of ignorance, “there exists neither a basis for the assignment of probabilities to outcomes, nor knowledge about many of the possible outcomes themselves” (Stirling, 1994, p.196).

When analysing incertitude in investment decisions, we typically identify a number of possible future outcomes and assign probabilities to them - we thus deal mostly with risk. Naturally, investments in the electricity sector comprise not only risk, but also the other states of incertitude for which we cannot specify possible futures, and where entirely unexpected events might occur (Lucas et al., 1995). Also, we might choose not to investigate all types of risk related to an investment decision, e.g. due to the scope of analysis or the necessity to reduce complexity of modelling. This should always be taken into account when interpreting model results. It is especially crucial as risks exist and affect reality, no matter if they are treated in models or not. All models ignore certain risks and uncertainties and thus investment decisions are almost always made in partial ignorance. The only solution to this is

identifying which risks are essential to know about for making informed decisions, developing models that can handle such risks, and staying informed and alert about the level of ignorance. The models developed in this dissertation contribute to a better understanding of risks and provide new solid approaches to integrate them in investment decisions.

In financial theory, risk is mostly used in the context of variability of returns on investment. It includes, but is not limited to, the possibility that undesirable outcomes occur, i.e. lower returns than expected. In most financial discussions (unlike in common day-to-day use of the word), risk entails both the possibility for lower and higher than expected returns.

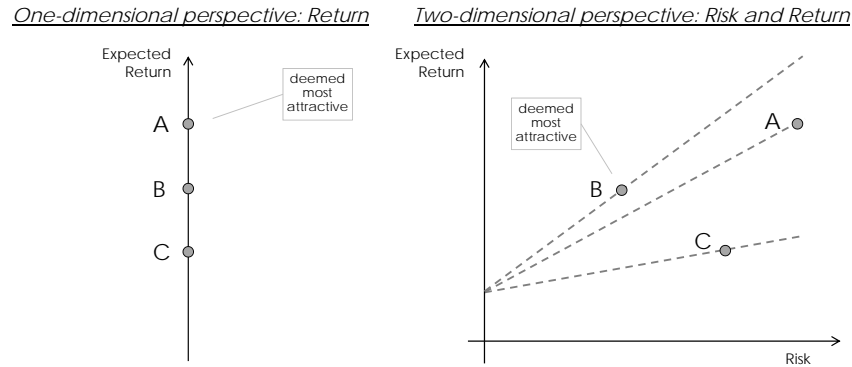
Risk is prevalent in energy markets. It affects decision problems at all stages of the supply chain. Equipment manufacturers, investors, producers, retailers and consumers are all affected, and risk is a central aspect in decision making for all of these private investors. For informed policy making, it is essential to base decisions on support instruments and support levels on models that reflect the key issues at stake for those private investors. Only so can incentives be set in an effective and efficient way. In the following, key issues in investment decisions for private investors in RES-E projects are shortly described and discussed.

#### **2.4.1 Investment in RES-E projects - key aspects in decision making**

Investment decisions for assets and capital projects are made primarily on the basis of expected future cash flows (Brealey and Myers, 2003). Simply put, positive cash flows (e.g. from electricity sales) should exceed negative cash flows (e.g. investment, operations and maintenance costs) over the lifetime of a project. Often, policy makers use this basic cost-benefit approach to determine the required support level for a support scheme (Gross et al., 2010). The prevalent method is to determine a ‘levelised cost of energy’ over the project lifetime and then match the payments from the support scheme so that the costs are covered and an adequate profit can be obtained by the investor.

However, such thinking is not the background for investment considerations of most private investors. Costs and revenues are equally important for investment appraisals. But a cost-benefit analysis and the estimation of expected returns is not sufficient to form a solid investment decision. Figure 4 illustrates this, based on a very simple example. Here, three different projects (A, B, C) are available for investment. If a one-dimensional perspective of maximising returns was adopted, then project A would be deemed most attractive. However, when recognising risks connected to the expected returns, one realises that the high returns of project A come at the expense of a very high level of risk. An approach considering both risk and

return (such as the mean-variance approach) would deem project B most attractive because it shows the best risk-return relationship (indicated by the steepest line).



**Figure 4:** Simple example illustrating the diverging conclusions on project attractiveness when considering only maximising returns (on the left) as opposed to considering the dichotomy of risk and returns (on the right)

A comprehensive investment appraisal does therefore not only comprise the expected costs of investment and the need to cover those. Investment decisions depend as much on variability of returns as on the return expectation itself. The returns required for investment depend on the risks related to the project. In a more complex setting than the example above, additional considerations, such as opportunity costs, irreversibility, decision flexibilities, etc., may also play a role. Furthermore, the financing possibilities of a project are just as important as a positive investment appraisal. A key challenge in obtaining financing for a project is the ability to quantify and manage the associated risks (Michelez et al., 2011). Weiss and Marin (2012) find that providing long-term revenue stability is critical for facilitating the financing of capital-intensive renewable energy projects and thus for their successful deployment.

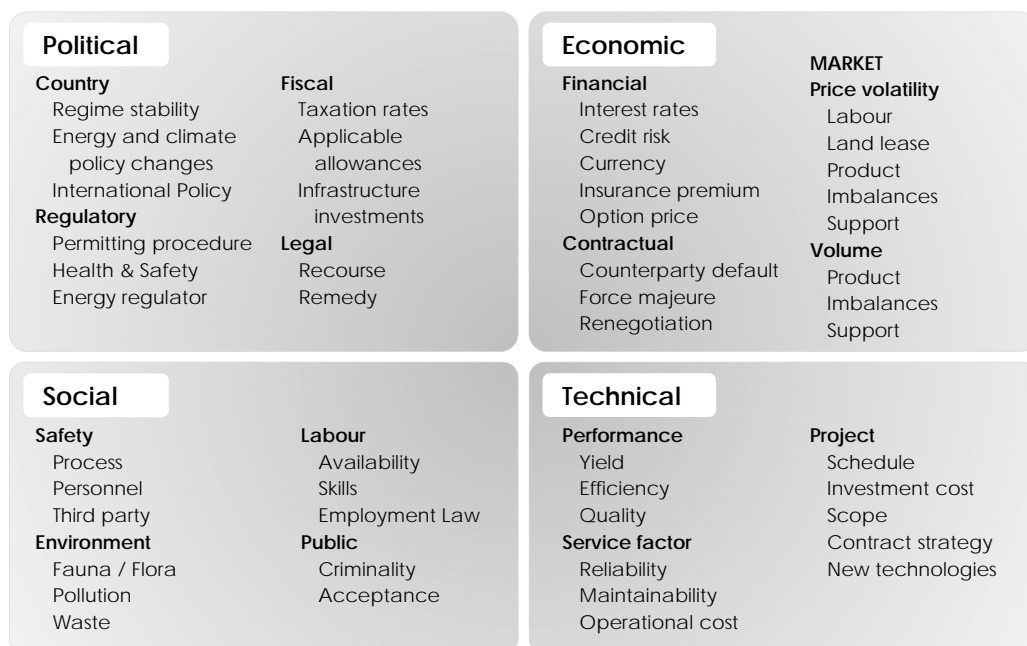
Overall, due to the exposure of risk, incentives from policy support that might appear sufficient to deliver policy goals when viewed in terms of levelised cost may not lead to the desired investment when risks and returns are taken into account (Gross et al., 2010). Investment risk, including various price risks affecting both the cost and the revenue side of cash flows, must therefore become an integrated part of policy considerations.

In practice, this means that a full investment appraisal, including costs and revenues as well as the resulting returns and their probability distributions, is required for an informed basis for policy decisions. The following section will investigate the risks that electricity producers face in more detail.

### 2.4.2 Risks in investment decision making

Although risks are specific for each project, risk categories and general elements are similar for most RES-E projects. In the following, these categories are described. After the identification and evaluation of project-specific risks, a firm has several options to deal with them: It will try to avoid as much risk as possible, through prudent project planning, clear communication and acquiring of expertise. It will then mitigate remaining project risks, through developing action plans for reducing probability and impact of potential adverse effects. Wherever possible, a firm will transfer negative impacts of a threat to a third party, either fully or partially (in terms of risk sharing), through insurance, warranties, guarantees, etc. If neither of the other measures are possible or desirable, a firm will have to adapt to the remaining risks, typically through establishing a contingency reserve (Michelez et al., 2011).

Risks are often distinguished in four categories: 1) Political risks, 2) Economic risks, 3) Social risks, 4) Technical risks. These categories and the major risks for renewable energy projects within the categories are illustrated in Figure 5.



**Figure 5:** Types of project risks, adapted from Michelez et al. (2011)

**Political risks** include risk of insurrection and expropriation (regime stability risks); international sanctions, international treaties that will change the operating conditions in a country; changes in taxation rates and applicable allowances, such as amortisation, depreciation, etc. (fiscal risks); risk of lacking government investment

in infrastructure (roads, grids, etc.); retroactive changes in operating conditions and lack of legal options (recourse); lacking enforcement of court awards (remedies); and changes in regulations, such as permitting regarding emissions, water, wildlife protection, or regulation on health and safety standards and reporting. Especially also changes in support schemes (discontinuation or reductions) affect RES-E projects heavily. Political risks are hard to manage for investors and often occur as discrete, sudden events. Country credit default swaps, risk sharing schemes and insurance can help to reduce some of that risk exposure (Michelez et al., 2011, p.9). Policy makers can help to significantly reduce risks in this area, e.g. through establishing government guarantees against retroactive changes or through reducing administrative and permitting risks, e.g. by establishing simplified and straightforward permitting procedures ('one-stop-shops'). Also, perceived risks from potential changes of support schemes can be reduced by creating stable, long-term and forward-looking renewable policy strategies with concrete targets that can tackle future problems without overly strong need for adaptation and amendment. We discuss this in Paper G.

**Social risks** include damage to equipment and injuries of personnel and third parties (safety risks); damage to flora, fauna, ground water, air and production of hazardous waste during construction and operating phase of the project (environmental risks); problems in the availability of sufficient labour resources with appropriate skills; and problems with public acceptance and criminal actions against the project (sabotage, terrorism, corruption). Firms will make health, safety, social and environmental impact assessments and handle identified risks through a respective management plan (Michelez et al., 2011, p.9).

**Technical risks** include the yield (amount of power produced and the possibility to sell it); the efficiency (especially with plants using fuel as input); the quality of the power produced (phase voltage, etc.); the reliability of production and maintainability (access to site, dependence on weather, availability of spare parts, shut-down times, etc.); unforeseen costs of operation (additional requirements, labour bottlenecks, etc.); risks in the construction phase (weather and other delays, equipment delivery problems, etc.); investment cost increases, incorrect specifications, changes in required components (project scope risks); and the emerging of new competitive technologies that could substitute the existing project. Many of the technical risks can be dealt with through prudent project management, guarantees, warranties, insurances (Michelez et al., 2011, p.9), and through choosing adequate equipment. Especially the latter is however very much dependent on the maturity of the technology. Generally, costs of technical risks reduce along the technology learning curve (see our discussion in Paper G). If the yield is not controllable but dependent on external factors such as weather, variability of project revenues is generally increased.

**Economic risks** include contractual risks, such as bankruptcy or wilful non-compliance of counterparties, force majeure, renegotiation requirements; financial risks, such as access to debt and equity and their rates (interest rates and credit risk), cost of insur-

ances (depending on breakdown statistics, third party liability, property loss, etc.), cost of derivatives, hedging, swaps (option prices), risk of exchange rate fluctuations; and market risks, which are discussed in more detail below.

Market risks are an important source for revenue risk, and are often not adequately recognised in policy making decisions (Gross et al., 2010). This dissertation focuses much on market risks. A RES-E project relates to several markets, including the labour market, the property market, the capital market, and the power markets. This dissertation focuses on power markets.

Power markets have been shortly described in Section 2.1. Three markets are most relevant: the futures market, the spot market, and the balancing market. RES-E projects are exposed to both volume and price risks on these markets. Volume risks stem from uncertain production and potential constraints in marketing the production, either because of market design (bidding sizes and time blocks) or the physical grid infrastructure. Spot prices are highly volatile, and volumes cannot be fully hedged through financial contracts (forwards are traded only for up to 3-6 years into the future). In balancing markets, the risk of imbalance volumes is especially high for intermittent energies: RES-E projects are exposed to imbalances from forecasting errors (the amount of which also depends on market design, e.g. gate-closure time of spot markets) *and* performance issues (such as break-downs). Balancing markets have also unknown future prices (which typically cannot be hedged by financial contracts).

Economic risks can be managed through insurances, guarantees, derivatives (incl. financial hedging), risk sharing (in joint ventures etc.) and risk transfer approaches (Michelez et al., 2011, p.9). Energy policy directly shapes the exposure of RES-E projects to power market risks. Policy makers can significantly influence the market risk exposure through choice and design of support instruments, as further discussed in Section 2.5. Also on the capital market, policy makers can help to reduce risk through ‘financing support’ measures, as described in Paper A, e.g. by provision of reimbursable equity or venture capital from governmental institutions, low interest loans, equity guarantees, loan guarantees and securisation products.

Overall, it is often argued that renewable energy projects inherently have higher risks than e.g. thermal generation assets based on fossil fuels (Wiser and Pickle, 1998). Next to the relative immaturity of technology and related higher risks, RES-E projects often have high upfront capital expenditures, which adds to the irreversibility issue related to investment decisions. Often, also a lack of natural hedges from commodity price development prevails. This is in contrast to fuel-fired power plants in markets where e.g. gas and electricity prices are fully or partially correlated and risk exposure to the spread is significantly lower than exposure to the single commodity.



### 2.4.3 Risk in financial theory

In the previous section, the various risks of renewable energy investments were described. However, it is not the single investment in isolation that determines the risk exposure of an investor, but its contribution to the risk of the portfolio that the investor holds. This idea has been developed in the seminal work by Markowitz (1952) and has dominated financial theory ever since. As many of the risks of different assets or stocks are correlated, overall risk exposure can be reduced simply by diversifying. Brealey and Myers (2003) write that “thanks to diversification the portfolio risk is less than the average of the separate stocks”, which is the basic principle of portfolio selection. The collection of assets or stocks that reduces risk the most by perfect diversification is called the ‘market portfolio’. The risk remaining in this portfolio is the systematic risk, or market risk  $r_m$ . When deducting the risk-free rate, one speaks of the market risk premium ( $r_m - r_f$ ). Systematic risks arise from dynamics on the market which are faced by all market players, e.g. government policy, international economic forces, or acts of nature. Effects arising from systematic risks affect the whole economy, i.e. market returns.

If an investor now considers investing in an asset, he should only consider how the new addition would affect his overall risk exposure in relation to the market portfolio. This is the main principle of the Capital Asset Pricing Model (CAPM), developed by Sharpe (1964) and Lintner (1965). They found that the relation between the expected risk premium of a single asset in comparison to the market portfolio is based on a direct and linear relationship, expressed by a factor  $\beta$ :

$$r_a = r_f + \beta(r_m - r_f). \quad (1)$$

The factor  $\beta$  describes the correlation of the asset to the market, and can be expressed as:

$$\beta = \rho_{a,m} \frac{\sigma_a}{\sigma_m}, \quad (2)$$

where  $\sigma_a$  is the volatility of the asset returns,  $\sigma_m$  the volatility of the market portfolio, and  $\rho_{a,m}$  the correlation of the two returns.

In financial theory, shareholders are thus only concerned with systematic risk, assuming that perfect portfolio diversification can be obtained at shareholder level without transaction cost (Lemming, 2003). In the long term, a well-diversified portfolio provides returns corresponding to its exposure to systematic risk. This simple idea is very helpful in many financial analyses. Unsystematic risks (also called specific or idiosyncratic risk), to which most of the risks discussed in the previous section belong, need not be considered for investment decisions. These principles are the basis for many standard approaches, like the discounted cash flow analysis and the mean-variance approach, which are used in this dissertation and are further described in

### Section 3.1.

However, this basic approach also contains simplifications and has several unsatisfactory features. The approach requires e.g. that all asset returns are (jointly) normally distributed random variables. A major assumption is also that all investors are rational and risk-averse, and markets are efficient. This assumption is related to work by Modigliani and Miller (1958) on firm capital structure: They showed that risk management in efficient markets is irrelevant and hedging cannot create shareholder value if the cost of assuming risk is the same inside or outside the firm. Potential market imperfections, such as cost of bankruptcy and financial distress, cost of funding new investments, corporate taxation, asymmetric information, and more are however not captured in this approach (Frenkel et al., 2005). In reality, those factors exist and justify active risk management by firms. We discuss this in more detail in Paper D and develop an approach to incorporate unsystematic risks into a model for comparing the attractiveness of different support schemes.

## 2.5 Renewable support policies and risk

The importance of considering risk in policy making has already been mentioned in Section 2.4.1. Considering risk implications can help energy policy become more effective and cost-efficient, as it allows support policies to be more specifically designed to address the investment problem at hand.

The need for policy making to actively engage with investment risk requires an understanding of sources, exposures and effects of risks on specific investor groups (Gross et al., 2007). It is therefore not only important to understand the risks RES-E projects face, but also how policy making can and will shape those risks. Some of these effects were already touched upon in Section 2.4.2, where it was described how energy policy schemes directly affect market risks (volume and price risks) and financial risks of an investment project.

The choice of support instruments has a significant effect on the risk of RES-E projects. Some instruments decrease risk exposure, whereas others increase it. Gross et al. (2007) go as far as to conclude that the choice of support scheme is really a choice about allocation of risk. Also, Fagiani et al. (2013) conclude that “policy makers should pay particular attention at how support policies affect the risk of renewable energy projects”.

Not only market risks are influenced by policies. Risks directly associated with governmental support schemes include also the lack of long-term uncertainty inherent in certain instruments and the risk of reduction in support level or discontinuation

of support for existing projects. This is especially the case for tax incentives and similar policy measures, as they often can be repealed quickly and easily by political decision (Michelez et al., 2011). It also includes other elements, such as the stability of the support policy, which partly depends on the way the scheme is financed. Financing through PSO and electricity bills generally is deemed a more stable option as compared to e.g. financing through taxes and levies (which is depending on political decision regarding budgets and might be subject to short-term changes).

Therefore, in order to make a full risk assessment of a support policy, not only the influence on revenues and market risks should be considered. Also many other aspects should be analysed, as discussed by Klessmann et al. (2008). These include the regulatory regime and grid access rules, the responsibilities and rules for forecasting and balancing of the RES production, the financing of support schemes and indirect cost (such as RES-related grid reinforcements), and potential conflicts with EU or international law, regulations or guidelines. Finally, also public acceptance could be an issue, i.e. how the support scheme is accepted by the energy producing industry, the energy consuming industry, the political parties and other stakeholders.

In the analyses undertaken in this dissertation, we focus mostly on economic risks and on one market (the power market). We can, with such partial analysis, not fully assess a support instrument, but we can make comparisons of different instruments in similar settings, e.g. as is required when considering a switch from one instrument to another. It is thus important in the context of the dissertation to highlight some of the risk implications of the major RES-E support instruments in regards to market risks.

Support schemes that ensure priority feed-in and guaranteed production off-take, can reduce some of the volume risk a producer faces when selling on power markets. Price risk can be decreased to a minimum with a guaranteed price level, as it is provided in FIT schemes. In FIP and TGC schemes, RES-E producers are fully exposed to power market risks. Traditional FIT schemes also exempt RES-E producers from participating in the balancing markets, so they are not exposed to related risks. In some more recent implementations of FIT (sliding premium systems), as well as in FIP and TGC schemes, RES-E producers are fully exposed to balancing market risks.

When specific support markets are needed, they create new forms of market risk exposure. In FIT and FIP schemes, no support markets are necessary. In TGC schemes, a market to trade green certificates is established. On this market, RES-E producers are exposed to volume risk due to uncertain production, and price risk as certificate prices depend on the demand and supply balance related to the quota set by government.

As we discuss in Paper G, traditional FIT mechanisms are thus usually the policy

instrument that reduces market risks the most, due to their inherent characteristics. Therefore, the literature describes the implementation of FIT schemes often as ‘low risk’ approach, and TGC schemes as ‘high risk’ approach (see e.g. Klessmann et al., 2008). However, under some market conditions, TGC can actually also lead to lower return variability than e.g. FIT schemes, as we show in Paper F. Additionally, the inherent risk characteristics of support schemes can be substantially altered by design specifications (e.g. sliding premiums, or caps and floors). In fact, Ragwitz et al. (2011) show that a gradual convergence of key properties in FIT and TGC implementations can be observed in Europe, with trends to provide differentiated technology-specific support, to enact quantity controls, and to introduce elements of exposure to more market risk.

It is important to recognise that risk reducing effects for private investors most often do not eliminate risks altogether. This is especially so for market risks - they are merely transferred to other actors. E.g. when RES-E producers are exempt from participating in balancing markets (as in traditional FIT schemes), the related risks are transferred to the off-taking entity.

In Papers B, C, D, and E, we analyse quantitatively, how higher exposure to market risks increases the project costs for RES producers and what the implications are on required support levels. In Paper F, we analyse how exposure to market risks affects investment decisions regarding investment timing and capacity choice (i.e. when and how much to build). In Paper G, we then also analyse the efficiency effects of different risk exposures in support schemes from a societal perspective.

### **3 Research methods: Renewable energy investments under uncertainty**

This section gives a short introduction to investment decisions under uncertainty and the formal framework employed in this dissertation. The main approaches used in the papers are described, first for the quantitative models (such as discounted cash flow analysis, real options analysis and Monte Carlo simulation), and then also for the policy analysis. Return and risk measures are described as well as stochastic processes relevant for the analysis. Also statistical tools, mostly applied implicitly in the papers, are explicitly mentioned here. Finally, the methods are critically discussed.

### 3.1 Quantitative models: Investment decisions under uncertainty

Dixit and Pindyck (1994) show that in general, uncertainty will push towards investment in flexible, less capital-intensive technologies. Additionally, the higher the uncertainty, the more will investment decisions be postponed. These two effects may work against the achievement of RES-E targets if they are not adequately taken into account in policy design.

Due to the uncertainties and risks involved with investments in renewable energy projects (as described in Section 2.4), methods are needed for assessing the attractiveness and profitability of investment that can cope with uncertainties and risks as integral part of the investment decision. In the following, the methods that are most relevant for this dissertation are described.

#### 3.1.1 Discounted Cash Flow Analysis

Discounted cash flow (DCF) analysis is the standard framework for evaluating investment projects. It is based on assessing costs and benefits over the lifetime of a project, and making them comparable by discounting of future prices and costs. These costs and benefits are purely based on cash flows into and out of the firm or the project (whatever the scope of the analysis), they are not based on accounting income. This means e.g. that investments are fully accounted for in the year where they occur and not according to their depreciations. Also, the analysis is based on free cash flows: for investment decisions, projects are in the first instance analysed as all equity-financed. The financing analysis is usually undertaken separately. In DCF analysis, the financing structure is only accounted for via the cost of capital (Brealey and Myers, 2003, p.127). Typically, a net present value (NPV) is calculated from the expected free cash flows of a project.

$$NPV = -CF_0 + \sum_{t=1}^T \frac{CF_t}{(1+r)^t} \quad (3)$$

where  $T$  is the lifetime of the project,  $CF_0$  is the cash flow in year 0 (typically the investment cost),  $CF_t$  are the free cash flows of time period  $t$ , a combination of revenues and costs (including tax payments, but excluding interests or other financing costs), and  $r$  is the discount rate, typically a weighted average of the cost of equity and cost of debt (WACC), depending on the expected financing structure.

If  $NPV \geq 0$ , the positive cash flows are greater than the comparable negative cash flows and the investment should be undertaken. The Internal Rate of Return

(IRR) is a related indicator that measures the return that a project would achieve at  $NPV = 0$ :

$$0 = -CF_0 + \sum_{t=1}^T \frac{CF_t}{(1 + IRR)^t}. \quad (4)$$

In DCF analysis, risk is accounted for. First, the cash flows used are all *expected* cash flows. This means that if there is uncertainty about their future development, then an assessment of their possible outcomes and related probabilities is made. The expected cash flows used in the DCF calculation are thus a synthesis of all possible outcomes into one single (or several) scenarios. The actual treatment of risk is through the cost of capital, which incorporates a premium for systematic risk usually determined using the CAPM as described in Section 2.4.3.

We apply general cash flow analysis in Papers B-F. Paper B deals with a single-year problem, while Papers C, D, E and F use discounting to compare net present values of investments. Papers C and E use an IRR measure, whereas Papers D and F directly use present values as indicators.

However, DCF analysis has several pitfalls in the way it handles uncertainty and risk. Not all relevant elements of an investment decision can be reflected in a single DCF analysis. All scenarios are static; strategic flexibility of decisions is not inherently analysed. Potential events that might, but not necessarily have to, occur (e.g. the default of a supplier), cannot be easily synthesised into a single scenario. Because of these and other limitations on how risk can be treated in the cash flows, many practitioners resort to adding a risk premium to the discount rate that should cover for additional, case-specific risks (Pratt and Grabowski, 2008). Although it can be a reasonable approximation in some situations, there are some pitfalls related to this approach. An illustrative example is the case in which losses are incurred in some outcomes. Discounting these losses at a discount rate that includes an additional premium, will lead to an NPV which is less negative than what it would be otherwise. Thus, the losses and their true financial costs are underestimated. A more accurate approach requires identifying and valuing risks more explicitly, e.g. by Monte Carlo simulation techniques.

### 3.1.2 Monte Carlo simulations

Monte Carlo methods use random sampling to obtain numerical results of an often complicated stochastic problem with multiple variables. Typically, many scenarios (in the thousands or ten-thousands) are created from random sampling. Based on these scenarios, a probability distribution of a target indicator is constructed, creating expected value and standard deviation of that target indicator as result. The

simulation technique in its modern form was first used by Stanislaw Ulam in 1946 (Rubinstein and Kroese, 2008), who made random experiments to investigate the behaviour of neutrons. The term ‘Monte Carlo simulation’ relates to the resemblance of the approach to playing and recording results at a gambling casino.

The great benefit of the Monte Carlo approach is that one can analyse stochastic problems without having understood the deterministic equivalent beforehand. So, it can be used to analyse stochastic problems that are too complex to being solved analytically. The approach is also flexible in dealing with different structures, and can e.g. be easily adapted to handling different stochastic processes. In contrast, analytical models are always specific solutions to certain problems.

Generally, Monte Carlo simulations follow a common structure:

1. Define possible inputs (including their stochastic characteristics)
2. Generate inputs randomly from the probability distributions
3. Perform a deterministic computation on the inputs for each scenario
4. Aggregate the results into an expected value and a probability distribution of the target indicator

We apply Monte Carlo simulations in Papers B, C, D and E. In the combination with DCF analysis, Monte Carlo simulations are a very useful tool to deal with risk of cash flows in a more accurate way than e.g. through adding premiums in the discount rate. The result of such enlarged DCF analysis is not a NPV value alone, but also its probability distribution. This can then be further analysed, e.g. using a mean-variance approach.

### 3.1.3 Mean-variance approach

The recognition that expected return and the related risk are the only two and equally important indicators relevant for private investment decisions is a cornerstone of modern portfolio theory as developed by Markowitz (1952). The underlying approach is often referred to as mean-variance portfolio approach. It assumes that every rational investor, who compiles a portfolio of investments, will select those investments that ensure the largest expected return of the portfolio at a given level of risk. In papers B and C, we use the mean-variance approach, though only in a special case as described by Sharpe (1994): We assume a very limited investment portfolio, in which a zero-investment strategy is added to an existing risk-less portfolio. This case can be used to analyse the comparable attractiveness of investment opportunities independent of pre-existing investor portfolios. The relevant indicator in such analysis is the Sharpe Ratio  $S$ , which sets the expected excess return of an

asset in relation to its standard deviation (Sharpe, 1994).

$$S = \frac{E[r - r_f]}{\sigma} \quad (5)$$

where  $r$  is the asset return,  $r_f$  is the risk free rate of return, and  $\sigma$  is the standard deviation of the excess return of the asset.

The Sharpe Ratio measures how well an investor is compensated for a risk taken. The higher the Sharpe Ratio for an investment opportunity, the more attractive it is. The approach is described and illustrated in more detail in Paper B.

It has to be noted that this approach is useful for objectively analysing the comparative attractiveness between two investment opportunities. It cannot be used to draw conclusions on the investment behaviour of single investors, who might have pre-existing risk exposures and portfolios.

Overall, the mean-variance approach allows for a correct representation of required return - as opportunity cost of the investment. This is not always the case in a DCF analysis with WACC-based discounting, because it (in the usual application) implicitly assumes that a project's risk is identical to the risk of the firm's existing portfolio and that the debt-equity ratio of the firm remains stable for all projects (Awerbuch, 1993). In the mean-variance approach, only the expected return is calculated for a given project risk, and thus this problem is avoided.

### 3.1.4 Real Options analysis

What DCF analysis and straightforward application of Monte Carlo simulations cannot cover, are decision flexibilities and strategies. They can only evaluate one given investment opportunity at a time, and do not recognise the option to modify projects, e.g. in terms of timing or sizing. Such options to modify projects are known as *real options* (i.e. options on real assets) and comprise the right, but not the obligation, to undertake a business initiative, for example beginning, expanding, abandoning or postponing an investment project. The real options approach inherently incorporates strategic flexibilities and can thus be applied to optimise investment decisions, e.g. by determining when and how much to invest. This is in contrast to DCF analysis, which is implicitly based on a 'now-or-never' decision and a passive holding of the asset after investment.

Myers (1977) was the first to use the term *real options*. He found that investment opportunities can be viewed as call options on real assets. This was four years after the notable work by Black and Scholes (1973) and Merton (1973), who first applied



option-pricing theory to the valuation of assets. The approach has its roots in financial engineering, but since the pioneering work of Myers, Black, Scholes and Merton, a broad field of real options analyses has developed, from commodity pricing over valuing operational flexibility, to optimising investment decisions under uncertainty. Dixit and Pindyck (1994) give an excellent introduction to real options analysis.

Real options are embedded in many decision problems, no matter if they are recognised by the decision maker or not. If they are not recognised in investment appraisal, the full information necessary for an informed decision may not be considered, and thereby asset values are often underestimated. The energy sector is an area where real options are highly used in research and also in the industry. This is due to several reasons: Energy investments often are 1) highly capital intensive and mostly irreversible, which is why reliable valuation and decision-making tools are very important; 2) operationally flexible, so that adequate actions after investment can improve the value of the asset. Moreover, the outputs of energy assets are mostly traded commodities, which implies that operations can benefit from option pricing methods.

Real options analysis deals with uncertainty through a mathematical representation of the underlying stochastic processes. A stochastic process is a sequence of random variables, an example being the random walk. This could be a physical process, e.g. the movement of a molecule through a liquid, but also the fluctuating price of a commodity, or the financial status of a gambler over time. Usually, the stochastic processes dealt with in real options analysis satisfy the Markov property, i.e. they have no ‘memory’: The future steps of the process only depend on its present state, and not on its previous movements. In financial models, the most basic Markov process is the Wiener process  $W_t$ , which has four main characteristics: (1)  $W_0 = 0$ , (2)  $W_t$  is continuous in time, (3)  $W_t$  has independent increments, (4)  $W_t - W_s \sim N(0, t - s)$ , for  $0 \leq s \leq t$ . From this, it follows that increments have a Normal distribution centered at zero. The stochastic process  $X_t = \alpha t + \sigma W_t$  is called a Wiener process with drift  $\alpha$  and volatility  $\sigma$ . This is the foundation of many of the stochastic processes used in real options analysis and in this dissertation. They are described in more detail in Section 3.1.5.

The real options approach delivers optimal investment and operation rules, which can be obtained from models developed for pricing options in financial markets. A dynamic programming approach or a contingent claims analysis can therefore be adopted. With such approaches, the value of options is determined with help of differential equations. To differentiate stochastic processes, it is necessary to make use of *Itô’s Lemma* (Itô, 1951), which is easiest to understand as Taylor series expansion (Dixit and Pindyck, 1994, p.79) with first and second derivatives: Let  $F(x(t), t)$  be the value of the option at time  $t$  and  $x(t)$  denote the fluctuating value

of the underlying asset at time  $t$ , then the resulting differential  $dF$  is:

$$dF = \frac{\delta F}{\delta t} dt + \frac{\delta F}{\delta x} dx + \frac{1}{2} \frac{\delta^2 F}{\delta x^2} (dx)^2 \quad (6)$$

where  $x(t)$  could e.g. follow a process  $dx = \alpha x dt + \sigma x \varepsilon \sqrt{dt}$  with drift  $\alpha$  and volatility  $\sigma$ , and a normally distributed variable  $\varepsilon$ . Note that the stochastic term is proportional to the square root of time. With  $dt$  becoming infinitesimally small, the stochastic term represents an increment of a Wiener process in continuous time:  $dz = \varepsilon \sqrt{dt}$  (Dixit and Pindyck, 1994, p.65).

In a related simple investment decision problem, one has the opportunity to make an irreversible expenditure  $I$  in return for a project currently worth  $x(t)$  at any point in time. To optimise investment timing, the critical value  $x^*$  must be found such that it is optimal to invest once  $x(t) \geq x^*$ . We find this by solving the differential equation from above and applying several boundary conditions. This process is described for a concrete case in Paper F. Here, it shall suffice to mention that the resulting investment rule in this simple example is:

$$x^* = \frac{\beta}{\beta - 1} I \quad (7)$$

where  $\beta$  is a known constant whose value depends on the stochastic parameters of process  $x(t)$ . From  $\beta > 1$  (necessary condition of the solution) follows that  $x^* > I$ . The NPV rule would in this simple example have suggested that investment is feasible already at  $x^* = I$ . Thus, there is a positive ‘wedge’ between the value that triggers investment  $x^*$  and the cost of investment  $I$ , due to the option value of waiting (Dixit and Pindyck, 1994, p.142). The real options model thus suggests later investment than the DCF model.

The real options approach can likewise be used to optimise decisions about sizing an investment, about utilising operational flexibility (e.g. ramping up and down), and about sequentially abandoning or expanding investment projects. Also, policies and policy uncertainties can be analysed. In Paper E, we draw from real options analysis to numerically (based on simulations) investigate operational flexibility (reflected in the question into which market an offshore wind park would sell). In Paper F, we derive an analytical solution to the investment problem of a wind park with decision flexibilities in timing and sizing (capacity choice). In both cases, we use a concrete case to investigate different regulations and policy options.

### 3.1.5 Stochastic processes

Modelling the dynamics of energy prices and other stochastic variables is critical for any valuation model that includes risk analysis. The analysis in this dissertation has a focus on finance and econometric models that represent price developments, mostly by stylised stochastic processes. We model stochastic processes in Papers D, E and F. In Paper B, we model prices and production values simply as random draws from a historic data sample. Alternatively, fundamental models can be used to determine future price paths. For this, typically complex energy system models are required such as the Balmorel model (Ravn et al., 2001), which we apply in Paper C.

Several different classes of stochastic processes are commonly used in financial analysis. Below, the processes most relevant for this dissertation are shortly described. The processes are, as a starting point, described as continuous-time processes. For the embedding in simulation models, stochastic processes need to be discretised. During discretisation, a continuous-time process is being replaced by an approximate discrete one (Conejo et al., 2010). We describe the discretisation approach for the different processes only where relevant for this dissertation.

**Brownian motion.** The term Brownian motion depicts a simple continuous-time stochastic process, and involves the Wiener process  $W_t$ , already explained in Section 3.1.4 above. A Brownian motion  $X_t = \alpha t + \sigma W_t$  has drift  $\alpha$  and volatility  $\sigma$ .

**Geometric Brownian motion.** The most famous and most often used stochastic price process is a variation of the Brownian motion where the *logarithm* of the random variable follows a Brownian motion, i.e.  $\ln X_t = S_t$  and  $dS_t = \alpha S_t dt + \sigma S_t dW_t$ . The solution for a geometric Brownian motion using *Itô's Lemma* is;

$$S_t = S_0 e^{(\mu - \frac{1}{2}\sigma^2)t + \sigma W_t}. \quad (8)$$

This process has the advantage that it always remains positive and that it mirrors the characteristics of many commodities well. It is simple to use and often facilitates analytical solutions to the investment problem. It is therefore most often used in financial models, e.g. also the Black-Scholes model (Black and Scholes, 1973). We use geometric Brownian motions for the model representation of gross margins in Paper F.

**Mean-reversion process.** The most applied mean-reversion process in mathematics is the Ornstein-Uhlenbeck process, a modification of the Wiener process. In this stationary, Gaussian and Markovian process, properties are modified so that there is a tendency of the stochastic process to move back towards a mean (i.e. the long

term equilibrium of prices):

$$dX_t = \kappa(\bar{X} - X_t)dt + \sigma dW_t \quad (9)$$

where  $\kappa > 0$  is the mean-reversion coefficient and  $\bar{X} > 0$  the long term equilibrium.  $\bar{X}$  can also exhibit a drift, i.e. be time dependent as  $\bar{X}_t$ . We apply this process in Paper E. For the simulation, we use the discretisation as first-order autoregressive process as proposed by Dixit and Pindyck (1994, p.76):

$$X_t = \bar{X}_t(1 - e^{-\kappa}) + (e^{-\kappa} - 1)X_{t-1} + \epsilon_t + X_{t-1} \quad (10)$$

where  $\epsilon_t$  is a normally distributed random variable with  $N(0, \frac{\sigma^2}{2\kappa}(1 - e^{-2\kappa}))$ .

**Multi-factor models.** One example for multi-factor models is the two-factor model by Schwartz and Smith (2000). The so-called SS-model consists of a long term process  $\xi_t$  modelled as a geometric Brownian motion, reflecting the uncertainty in the equilibrium price, and a short term process  $\chi_t$  modelled as an Ornstein-Uhlenbeck process, reflecting random deviations from the equilibrium price. The two processes are additive, considering the logarithm of the modelled commodity price:

$$\ln(S_t) = \xi_t + \chi_t. \quad (11)$$

We apply the SS-model in Paper D. For simulation, we discretise using the approach described by Davis (2012), in which  $\xi_t$  is discretised by an Euler scheme and  $\chi_t$  following Phillips (1972):

$$S_{t+\Delta t} = \exp(\xi_t + \mu_\xi \Delta t + e^{-\kappa \Delta t} \chi_t) \exp(\sigma_\xi \sqrt{\Delta t} \varepsilon_t + \sigma_\chi \sqrt{\frac{1 - e^{-2\kappa \Delta t}}{2\kappa}} \bar{\omega}_t) \quad (12)$$

where  $\varepsilon_t$  and  $\bar{\omega}_t$  are random elements with  $\varepsilon_t \sim N(0, 1)$  and  $\bar{\omega}_t \sim N(\rho_{\chi\xi}\varepsilon_t, 1 - \rho_{\chi\xi}^2)$ , and  $\rho_{\chi\xi} \in [-1, 1]$  expresses the correlation between the increments of the two processes ( $dz_\xi dz_\chi = \rho_{\chi\xi} dt$ ).

**Jump processes.** A jump or spike process has occasional extreme movements rather than small continuous changes. Jump diffusion processes and the consequences of such discontinuous processes for option pricing were notably discussed by Merton (1976). Due to the variation of the characteristics of jumps or spikes in commodity processes, there exists no dominant modelling approach. Often, Poisson distributions are employed (see e.g. Hambly et al., 2009). In Paper E, we use a jump process to model stochastic failures of interconnector lines. Since line failure events have very special characteristics and we did not find a satisfying existing modelling approach, we have developed our own jump diffusion model based on a Poisson distribution. Its stochastic process is characterised by rare but extreme events that cause an immediate drop of full line availability. The process thus has a ‘default’ value of 100% line capacity ( $\hat{y}$ ), which is affected by random events (triggered by  $i_{(t,\epsilon)}$ ) that

cause an immediate drop of capacity from 100% to 0%, lasting for a random amount of time (triggered by  $j_{(t,\theta)}$ ), after which an exponential ramping process is started at recovery rate  $\kappa$ . The model is mathematically described as:

$$y_t = \hat{y} - \hat{y}i_{(t,\epsilon)} - (\hat{y}j_{(t,\theta)} + (e^{-\kappa} - 1)y_{t-1} + y_{t-1}) \quad (13)$$

where  $0 \leq y_t \leq \hat{y}$  is the available interconnection capacity at each point in time with  $\hat{y}$  as maximum available interconnection capacity, also serving as the jump size in the Poisson process (meaning that the failure is expected to always affect full capacity),  $\kappa$  is the recovery rate of the exponential process towards  $\hat{y}$ ,  $i_{(t,\epsilon)}$  is the variable that activates the line failure, with

$$i_{(t,\epsilon)} = \begin{cases} 1, & \text{for } \epsilon_t > 0 \\ 0, & \text{for } \epsilon_t = 0 \end{cases} \quad (14)$$

where  $\epsilon_t$  is a Poisson distributed random variable with mean of  $\lambda$ ,  $\epsilon_t \sim \text{Pois}(\lambda)$ ,  $\lambda$  reflects the expected number of line failures per year.

$j_{(t,\theta)}$  is the variable that activates the recovery process after an outage, with

$$j_{(t,\theta)} = \begin{cases} 1, & \text{for } t = t_p + \theta_t \\ 0, & \text{for } t \neq t_p + \theta_t \end{cases} \quad (15)$$

where  $t_p$  is the maximum value of  $t$ , in which a line failure last occurred, with  $t_p = t$  at  $\epsilon_t > 0$ ,  $\theta_t$  is a normally distributed random variable with mean of zero and standard deviation of  $d$ ,  $\theta_t \sim N(0; d)$ , and  $d$  reflects the range of outage durations.

**Deterministic and cyclical effects.** In most electricity markets, spot prices are characterised by daily, weekly and seasonal cycles, high volatility, mean reversion, and occasional spikes (Weber, 2005, p.15). This is to a large extent due to the non-storability of electricity. In contrast, futures and forwards prices for electricity often exhibit no cycles, lower volatility, and little mean reversion, as related contracts are ‘storable’ (Weber, 2005, p.17). In spot price modelling, cyclical effects are usually distinguished into hour-of-the-day effects, day-of-the-week effects, and seasonal effects (Weber, 2005). They can be accounted for in the price process through the inclusion of continuous variables, such as *sine* and *cosine* functions (see e.g. Pilipovic, 2007), through monthly, daily, or similar dummies (see e.g. Cuaresma et al., 2004), or through a combination of both (see e.g. Lucia and Schwartz, 2002). In addition to these pure time effects, also more fundamental factors are sometimes included in stochastic price processes, such as meteorological conditions (outside temperature, rainfall, wind speed), or system characteristics (number of operating power plants, etc.) (Weber, 2005). Deterministic and cyclical effects are not accounted for in this dissertation, as the focus lies on the creation and application of models for policy analysis rather than on mathematical modelling alone.

**Advanced stochastic models.** To cope with the complexity of electricity price processes, several more advanced classes of discrete stochastic models have been de-

veloped. The *autoregressive moving average* (ARMA) model is a stationary process including temporal correlations, which allows for general impacts of past observations on today's prices (see e.g. Box et al., 2008). It should be noticed that, because of the temporal interdependencies, ARMA processes have no Markov property and cannot be solved through the Itô calculus. The *autoregressive integrated moving average* (ARIMA) model is a further development of the ARMA model, allowing for a non-stationary process achieved through integration. The *generalised autoregressive conditional heteroscedasticity* (GARCH) model allows for including conditional probabilities for large (or small) price changes depending on preceding price movements. In the analyses undertaken as part of this dissertation, none of these advanced models have been applied.

### 3.1.6 Formal model framework

A common first step to analyse decision problems under uncertainty is defining some notation and common indicators for analysis. In a basic setting, quantitative models for decision problems essentially comprise of (based on Weber, 2005):

1. a set of decision alternatives
2. a set of possible states of the world
3. a results function
4. an objective function

The specific indicators chosen in each analysis depend heavily on its purpose and approach. The set of decision alternatives could e.g. consist of two different support instruments (FIT and FIP) that shall be compared. It could also contain an (almost) infinite number of elements, e.g. when the required support level for an instrument shall be determined.

The set of possible states of the world includes different sets of state variables. In the presence of risk, these state variables are described as random variables with probabilities assigned to each possible state, for example, following Conejo et al. (2010), as  $\lambda(\omega)$ ,  $\omega = \{1, \dots, N_\Omega\}$ , with  $N_\Omega$  as the number of potential outcomes and  $\Omega$  as the outcome space. Each realisation of  $\lambda(\omega)$  has probability  $\pi(\omega)$ , defined as

$$\pi(\omega) = P(\omega \mid \lambda = \lambda(\omega)), \text{ where } \sum_{\omega \in \Omega} \pi(\omega) = 1. \quad (16)$$

Stochastic processes can in this framework be viewed as a set of random variables  $\Lambda_t$ , indexed over time  $t$  (see Weber, 2005).

The results function can vary greatly depending on the analysis. As this dissertation focuses on micro-economic analysis and effects of policy instruments on investment

incentives, the result functions always revolve around the value of a project or the profit of a firm. More concretely, we use the indicators Shareholder Value, NPV, IRR and Return on Asset (RoA) in the different papers. As a secondary result function, we also calculate the required support levels.

The objective function also greatly depends on the type of analysis undertaken. One can either make a descriptive analysis, without determining a distinct objective function. Then, the different outcomes of the result function are analysed and compared. We make such a descriptive analysis e.g. in Paper C. Alternatively, a target value is determined for the result function (e.g.  $NPV = 0$ ) and then the different decision alternatives are analysed and compared. We use this approach in Papers B and D. In *optimisation models*, an objective function is explicitly defined, typically a maximisation or minimisation of the results function. We develop such an optimisation model in Paper F.

### 3.1.7 Risk and return measures

As described above, the analyses in this dissertation all deal with measuring the value or return of a project or a firm. Using the notation from above, this can in its simplest form be described as random variable  $\lambda$  with two moments that are important for the analysis: 1) mean or expected value  $\bar{\lambda}$  and 2) variance  $\sigma_\lambda^2$  (or standard deviation  $\sigma_\lambda$ ):

$$\bar{\lambda} = \mathcal{E}\{\lambda\} = \sum_{\omega \in \Omega} \pi(\omega) \lambda(\omega), \quad (17)$$

$$\sigma_\lambda^2 = \mathcal{V}\{\lambda\} = \sum_{\omega \in \Omega} \pi(\omega) \left( \lambda(\omega) - \mathcal{E}\{\lambda\} \right)^2. \quad (18)$$

Risk measures can be used to understand and control the risk of undesirable outcomes. Examples of risk measures are (Conejo et al., 2010, p.121): Variance of profit, probability of falling behind a target value, expected value of the profit being inferior to a specified value (Value-at-Risk, VaR). All of these rather simple risk measures imply a Gaussian distribution of profits. Risk management strategies that do not need this constraint, are e.g. based on imposing stochastic dominance constraints (Borch, 1969). These are however not dealt with in this dissertation.

The variance of profit is the simplest risk measure, directly utilising the stochastic parameter  $\sigma^2$ . We use the variance of profit or project value as risk measure in Papers B, C and E for determining the attractiveness of investments in the dichotomy of

return and risk. The variance  $\mathcal{V}(x)$  of profit  $f(x, \omega)$  can be described as:

$$\mathcal{V}(x) = \mathcal{E}_\omega \left\{ \left( f(x, \omega) - \mathcal{E}_\omega \{ f(x, \omega) \} \right)^2 \right\}. \quad (19)$$

In the Value-at-risk measure, a quantile  $\alpha \in (0, 1)$  is specified representing the risk tolerance of an investor. From the specified  $\alpha$  and the mean profit, a value  $\eta$  is calculated, so that the probability of obtaining a profit less than  $\eta$  is lower than  $1 - \alpha$ :

$$VaR(\alpha, x) = \max \{ \eta : P(\omega \mid f(x, \omega) < \eta) \leq 1 - \alpha \}, \forall \alpha \in (0, 1). \quad (20)$$

Commonly used values for  $\alpha$  are derived from the standard deviation  $\sigma$ . Using one standard deviation corresponds to 68.27% probability that the profit will lie above the calculated value  $\eta$ , using 2- $\sigma$  corresponds to 95.45% probability, and 3- $\sigma$  to 99.73% probability. We apply the VaR risk measure in Paper D for determining the required liquidity reserve in a firm.

The simplest return measure (in percent) of a price  $S_t$  in a one-period model is (Pilipovic, 2007):

$$\frac{d\tilde{S}_t}{S_t} = \frac{d\tilde{S}_{t+dt}}{S_t} - 1 \quad (21)$$

where  $dt$  is the time period between price observations  $\tilde{S}_{t+dt}$  and  $\tilde{S}_t$ . We use this return measure to generate time series in Paper D.

An investment-specific return measure is the single-period Return on Asset (RoA), in Paper B applied to an investment as:

$$RoA = \frac{CF_t}{I} \quad (22)$$

where  $CF_t$  is the net cash flow in a year, and  $I$  is the total investment undertaken for the project.

In Papers C and E, we use the multi-period return measure IRR, as described in Section 3.1.1. Papers D and F deal directly with project values and shareholder values without calculating returns.

### 3.1.8 Statistical tools applied

Two different sets of statistical tools are applied in this dissertation, namely time series analysis and distribution analysis. We use these statistical tools to determine



which stochastic processes and shapes of probability distributions are appropriate to employ in the models and also to determine the appropriate values of key model parameters.

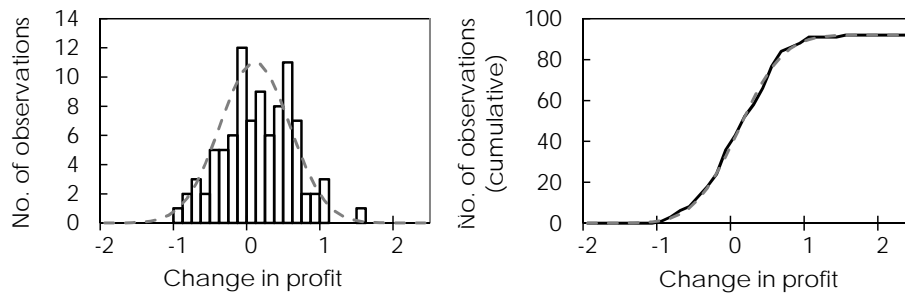
A time series is a collection of well-defined observed data, obtained through repeated and consistent measurement or recording at equal time intervals. A time series can be analysed according to its trend (long term direction), systematic movements (e.g. seasonal or weekly changes), and irregular short term fluctuations. When analysing risk, often only the irregular short term fluctuations, i.e. the unsystematic movements, are of interest. Therefore, potential seasonal patterns have to be removed from the time series before estimating parameters.

For example, in Paper F, we employ a least squares linear regression to determine seasonality in power prices, certificate prices and wind production data. In the least squares method for data fitting, one creates a function that shall describe the time series, e.g.  $f(x, \beta) = \beta_0 + \beta_1x + \beta_2y + \beta_3z$ . It can also contain continuous variables, such as *sine* or *cosine*. This function is then fitted to the time series so that the sum of the squared residuals (as the difference between an observed value and the modelled value from the function) is minimised. The movements in the time series that cannot be described by this fitted function are then deemed unsystematic. In Paper D, we use least square regression for determining correlation and volatility parameters in the price processes.

For the simulations, we derive parameters from different time series. We calibrate the stochastic processes in the models to reflect historic developments of e.g. the spot and futures prices on the Nordic and German markets (Papers B, C, F and D, respectively), wind production in the North Sea (Papers B, C) and the Baltic Sea (Papers D, F). For this, we e.g. derive the parameters mean, drift, standard deviation, and mean reversion. We use mainly least squares regression, in an approach similar to the one described above. The calibrating of parameters for the SS-model is described in some detail in Paper D.

In distribution analysis, we estimate parameters from sample statistics. Time aspects do not necessarily play a role here. We strive to find the best (or adequately applied) shape of probability distribution to be employed. For commodity prices, often a normal or lognormal distribution is adequate (Hull, 2002). For wind production, also Weibull distributions are often used, as we e.g. do in Paper D. Also in distribution analysis, least squares estimation can be used for parametrisation. For distributions in which the random element is not normally distributed, the maximum likelihood estimation is though usually preferred. In maximum likelihood estimations, parameters for a given probability distribution are determined so that it maximises the likelihood function, i.e. the fit of the selected model to the observed data. We apply this method to determine parameters of the Weibull distribution in Paper D.

There are several different statistical tests for determining the ‘goodness of fit’ for fitted curves and probability distributions, all of them have their advantages and disadvantages. A simple method, which we have used for testing curve fits in Papers B, D and F, uses the squared value of the correlation coefficient ( $R^2$ ) between two variables  $X$  and  $Y$  (Madsen, 2011, p.114).  $R^2$  expresses how large a part of the variation in  $Y$  is explained by  $X$ , and thus how much of the actual uncertainty in the underlying data is captured or explained by the model (Pilipovic, 2007, p.84). The closer  $R^2$  gets to its maximum value 1, the better the fit. To test for normal distribution in a slightly more elaborate way, we have in Paper F chosen to apply the Kolmogorov-Smirnov test (see Corder and Foreman, 2009, p.26ff). In this test, the  $H_0$  hypothesis is that the data has no normal distribution, and it is tested if that  $H_0$  hypothesis can be rejected with sufficient confidence. The Kolmogorov-Smirnov test quantifies the distance between the empirical cumulative distribution function of the data sample and the one of a normal distribution, as illustrated in Figure 6.



**Figure 6:** Visualisation of data fitting to a probability distribution, as applied in Paper F

### 3.2 Policy analysis: Renewable support and risk

This dissertation focuses on the area of governmental policy. In this, policy analysis studies the actions of public authorities within society. It can best be understood as an applied scientific sub-field, drawing on previously established knowledge and concepts (Knoepfel, 2007, p.3). It consists of three analytic areas: the interaction between public and private actors, public problems and comparative analysis (Knoepfel, 2007). The first area deals with describing and understanding three basic elements of a state: the public and private actors, their resources and the institutions that govern their actions, as well as their interactions. A focus of related empirical analysis is the daily practice of public administrations and their services from a social, economic and political perspective. The second area deals with structures and bureaucratic procedures, including the professional management of public administrations and the resources at their disposal. In the third area of comparative analysis, the quality of administrative products and policies is evaluated, e.g. based on a benchmarking principle.

This dissertation neither discusses the theories of the state, nor tries explaining how public action functions. In the different papers, we only touch upon the first of the above described areas. We make, amongst others, a historical analysis of policy instruments applied by European Member States (Paper A). The principles followed for this analysis are purely statistical: a data basis of information regarding applied support policy types from 2001-2011 was established from primary and secondary literature, i.e. government publications, laws as well as summary and evaluation documents from the European Commission and different project reports. The criteria for the definition of ‘active’ support schemes were precisely set: they must be decided, implemented, in force and open for new RES-E projects in the respective year. A purpose of the paper was also to reveal certain trends in policy making. We did however not evaluate or explain these trends.

We also make economic analyses of different policy instruments and their effects on private actors (Papers B-F). We describe consequences for policy decisions, such as support levels required to give adequate investment incentives. Finally, we make a policy analysis combining approaches from transition theory and strategic niche management with approaches from economic theory to explain dynamics in energy policy processes (Paper G). Transition theory is concerned with the description and explanation of gradual, long-term processes in which society or a complex subsystem of society (like the energy system) changes or evolves fundamentally (Rip and Kemp, 1998; Rotmans et al., 2001). Often, transition processes are analysed by adopting a multi-level perspective (MLP), as introduced by Geels (2004). The levels are 1) Niches, where new technologies emerge; 2) Regime, consisting of technical infrastructure and other material elements, rules and regulations as well as actor networks and social groups; 3) Landscape, the exogenous environment including macro economy, policy making and cultural patterns.

This analytical framework helps us to describe and explain certain developments in energy systems and related policy making. For our purpose, niches and their strategic management are the most important element for analysis, as they are crucial for triggering the start of a transition. In the energy system, a transition towards sustainability is desired, and renewable support instruments are the policy of choice for that in most countries. Risk reduction is a central aspect in niches: Stabilising revenue streams and technology-specific price guarantees are a major source of protection and required for technologies to eventually break through on the market (Finon and Perez, 2007). In this, our analysis also touches upon certain aspects of innovation processes, especially regarding drivers for technology cost reductions and related risk aspects.

When evaluating the success of policies, it is of utmost importance to clearly define the policy goals that a policy result shall be measured against. As shortly mentioned in Section 2.3.1, policy goals can change over the course of an energy transition. In Paper G, we discuss some implications of changing policy goals. Such development

can significantly alter e.g. the definition of effectiveness and has severe implications on the evaluation of related policies. These dynamic effects should always be taken into account in policy analysis. Furthermore, some studies implicitly assume that the ultimate goal of all policies is delivering a single target at the lowest costs possible. In reality, this is by far not always the case, as often policy schemes are based on complex objective functions, and RES-E deployment targets are e.g. combined with expectations on domestic technology development, job creation, and more.

These are some of the most relevant aspects for the policy analysis undertaken within this dissertation, and are of concern for all Papers A-G.

### 3.3 Discussion of methods applied

The above descriptions make clear that this dissertation does not focus on developing and improving one single methodology or one type of analysis. Rather, different methods and approaches are employed in the different papers. This is due to the deliberate decision of tackling the same research question from different perspectives. As a consequence, the adopted approaches contain certain simplifications which could have been avoided e.g. if focus would have been on developing a single methodology throughout the dissertation. This especially concerns price processes and risk measures employed, and also the market elements covered. Still, methods could be refined and became more elaborate throughout the course of the dissertation.

All analyses assume mostly constant parameters (i.e. volatilities and interest rates are not changing over time) and are limited to spot and forward markets for electricity. In reality, also balancing markets play an important role in investment decisions, both as cost element and as option for additional income. We mostly assume that financial support is paid out throughout the lifetime of a project. This makes the results more transparent and easier to compare between different support schemes. In reality, most support schemes in Europe grant support for 15-20 years only, regardless of the actual project lifetime. Therefore, most of our resulting support levels seem rather low when compared to reality.

In general, we implicitly assume for the analysis that markets are efficient, arbitrage-free and without transaction costs. In Paper D, we relax this assumption somewhat by also considering firm-specific risks and costs of risk management related to avoiding financial distress. We base all our analysis on a general no-excess profit condition, which is common for competitive and efficient markets in neo-classical models (Shoven and Whalley, 1992): we expect that the investment cost of each technology will in the long run be exactly covered by the sum of all operating margins over the lifetime. This means that when assessing attractiveness for investment, the  $NPV = 0$  criterion is the benchmark.

In Papers B, D, E and F, we adopt a single-investor perspective. We thus implicitly assume that the single investor acts as price-taker on the market and his actions do not influence the market prices. This excludes e.g. effects on market prices through increased wind production volumes after investment. In Paper C, some of these effects are captured by using an energy system model.

Not all scholars agree with taking a single-investor perspective in all circumstances. E.g. Weber (2005, p.246) argues that “in order to derive valuable results for the single investor, it is obviously necessary to treat the whole industry equilibrium”. Making only partial models for specific investment examples is surely based on a narrow scope and it is not certain if the results can be extrapolated into a larger system context. - However sometimes it is necessary to select specific questions and investigate them in more detail. From the experience gathered in this dissertation, it can be concluded that, although energy systems models are often required, it can be sufficient for some types of analysis to only treat the impacts on a single investor. We could confirm this by making a similar analysis first using a partial model in Paper B and then an equilibrium model for the whole energy system in Paper C. The results and conclusions regarding implications on choice and level of support schemes are comparable.

The narrow single-investor perspective also comes with certain other restrictions. We can e.g. not capture long-term structural effects on market prices, which should always be investigated in an energy system context. Neither can we investigate mutual reinforcing processes (i.e. between price developments and bidding strategies). For this, an agent-based system model would be required. We have tried to address this issue and broadened the scope of the final Paper G into a wider (macro-)economic perspective.

The approaches in our papers have three major differences, which might affect the comparability of results. We made different methodological choices regarding: (1) which risks to include in the analysis and how to incorporate them; (2) the modelling of stochastic variables; and (3) the solution process. It is clear that results from a simulation approach (as adopted in Papers B-E) cannot be directly compared to an optimisation approach (as adopted in Paper F). Thus focusing on Papers B-E, major differences can be found in the handling of stochastic variables. In Paper B and C, we do not model stochastic processes, but treat prices and other stochastic factors (such as wind production) as independent variables. E.g. prices are modelled as random deviation from a long-term equilibrium. This is certainly a strong simplification and does not really reflect the price paths that commodities usually undergo. In Papers D, E and F, we do model stochastic processes, however with different levels of detail. Paper F uses a rather simple geometric Brownian motion, Paper E uses a mean-reversion process, and Paper D uses a more elaborate two-factor model. The difference between the latter two is that in the two-factor model, the long-term equilibrium price is modelled as stochastic variable, whereas the simple mean-

reversion process only implements a constant drift. We can however see that the results actually do not diverge significantly over long time horizons (like a project's lifetime).

When comparing the different methods applied, it becomes apparent that each method has its advantages and disadvantages. The real options approach with closed-form solutions (as applied in Paper F) can optimise investment decisions and leads to exact results. Once the model is developed, results are quickly obtained simply by inserting the respective parameters into formulae. However, it is complex to develop the model in the first place, and once created, it is very specific to a certain problem. A simulation approach (as applied in Papers B-E) with numerical approximation does not require a full mathematical representation of the underlying stochastic relationships and can flexibly incorporate structural changes of the investigated problem. Computation time can though be substantial, especially when many Monte Carlo simulations have to be performed for results to converge. From the analysis undertaken and the results obtained with the different approaches, it can be concluded that all methods provide adequate means to answer the research question, however at different levels of detail. The choice of method will thus primarily depend on the specific situation in which the analysis shall be made, i.e. whether it is more important to quickly set up the model or to quickly apply the model.

With the increasing level of detail and treatment of additional risks in the different papers, also the level of ignorance (as discussed in Section 2.4) is reduced. Still, many types of risks are excluded from the analysis, such as the risks related to discontinuation of support schemes or retro-active policy changes. This should be kept in mind in the interpretation of results from our analyses. Further research would be required to quantify the significance of having excluded the remaining, potentially relevant types of risks.

Most of the analysis is in some way based on the principles of portfolio theory. We have though only adopted a quite narrow perspective in dealing with investments and their attractiveness. We have not analysed the behaviour of individual investors, who have pre-existing assets that might be (partially) correlated to the new investment option. Portfolio composition effects could significantly alter the opinion of individual agents about the attractiveness of certain investments. In this dissertation, focus was on an objective measure that helps comparing different support schemes. However, to fully understand investment dynamics and the behaviour of individual investors, a complete portfolio perspective would be necessary.

Additionally, we also adopt different assumptions and scopes in the papers. While Paper B was based on a pre-tax analysis for a representative year, and Paper C on a pre-tax multi-year analysis, have we broadened our perspective in Paper D into a post-tax, multi-year analysis. We investigate offshore wind parks both in the North Sea and in the Baltic Sea, both on the Nordic market and on the German market,

etc. To mitigate the issue of differing assumptions, we have tried to always include a number of sensitivity analyses on relevant input parameters.

In general, we deemed it more important to refine and improve the models applied and to vary assumptions covering a broader scope, than to have fully comparable results.

## 4 Results and discussion: Risk implications of energy policy

In this section, the highlights of the research undertaken as part of this dissertation are summarised and discussed.

### 4.1 Results of Papers A to G

In Paper A, we analysed the development of RES-E support policies in Europe and identified dominant trends in national policy making. We found that all major support instruments used in Europe are generation based, i.e. paid out per unit of eligible electricity produced. Investment grants, tax breaks and financing support are only used as supplementary instruments. Feed-in tariffs (FIT) are by far the most dominant major support instrument in Europe. Feed-in premiums (FIP) have started to become increasingly popular, having recently surpassed tradable green certificate schemes (in number of countries that implemented them). Next to the establishment of support schemes in all European Member States, two trends have been identified: (1) differentiating policy for installation sizes and (2) combining different policy types in parallel implementations. The chosen policy types and the scope in which they are used are becoming more similar across Europe - they show signs of convergence. A ‘top-down’ harmonisation of RES-E policy driven by the EU becomes in this respect less controversial or even dispensable. Paper A served as basis for the further research in the dissertation, providing an understanding of which policy instruments are important to analyse, namely mostly FIT and FIP, and in which scope and implementation they should be considered, namely technology-specific for certain installation sizes. Also, it was deemed advantageous to focus mostly on national policy making rather than European harmonisation.

In Paper B, I analysed risk implications of FIT and FIP using a mean-variance portfolio approach. By quantifying risk-return relationships for an exemplary offshore wind park, I could show that FIT schemes systematically require lower direct support

levels than FIP schemes while providing the same attractiveness for investment. The attractiveness of investment was measured by the risk-return relationship between a representative single-year Return-on-Asset and its standard deviation, as depicted by the Sharpe Ratio. I found that the support level required to trigger investment in an offshore wind park in Denmark under a FIT scheme was 5-10 EUR/MWh (or 40% at most) lower than under a comparable FIP scheme. The difference was highest at low support levels. At the same time, the model was most sensitive to changes in assumptions at low support levels. Results remained robust in the relative conclusions for all undertaken sensitivity analyses.

In Paper C, we applied the same mean-variance approach as in Paper B in a new context. We enlarged the analysis and used the energy systems model Balmorel (Ravn et al., 2001). Doing this, we could capture additional market effects of the wind park. We also broadened the perspective into a multi-year framework to benefit from the market and system developments already included in the energy systems model. The indicator for attractiveness of investment was thus changed to be based on the modified internal rate of return. Here, we found that the FIT scheme required a 7.1 EUR/MWh (or 13%) lower support level than a comparable FIP scheme, at comparatively high support levels. The complexity of the energy systems model did not allow us to test the results for many different support levels or to undertake as detailed a sensitivity analysis as in Paper B. We could, however, confirm the overall results of Paper B and conclude that risk implications of support policies are equally significant in an energy systems context.

In Paper D, we analysed how risk exposure from different support schemes affects the investment incentives from private investors, both in terms of systematic and unsystematic risks, by adopting a net cash flow approach. The two risk types were implemented for the case of a project-specific firm through variation in cost of equity (through a beta analysis) and through liquidity management. We found that the support levels required to give adequate investment incentives (here measured using the Shareholder Value as indicator) for an offshore wind park in the German Baltic Sea are 4.3-5.9 EUR/MWh (or 5-7%) lower under a FIT than under a FIP scheme. We could confirm that our model overall aligns with what is underlying official government policy, by comparison with the actual feed-in tariffs for offshore wind in Germany.

In Paper E, we made a risk analysis for different regulatory options in offshore grids. Recognising the fact that offshore wind parks might in the future have the option to be connected to not only one but several neighbouring countries, we investigated the effects of different regulatory choices regarding market access and pricing rules. Our results show that the choice of regulatory regime can have significant impact on the value of a wind park (we used the internal rate of return (IRR) as indicator) and on the value of the interconnection capacity in the offshore grid (we used the net present values of the congestion rents as indicator). In general, it is mostly a question of re-



allocating income between wind park and transmission system operator, but several constellations can also lead to socio-economically suboptimal situations, due to adverse incentives for electricity flows from support mechanisms. This is, if countries do not cooperate regarding support payments. We found that primary market access is most attractive to wind park investors, especially with the option to connect to additional countries, and can increase the IRR by up to 33%. When creating an offshore hub price zone, the wind park can face severe negative impacts from connection to additional countries that can reduce the IRR by up to 15%. This effect is partially counterbalanced by lower exposure to line failures from improved export options. These risk implications must be considered, not only when designing the regulatory framework for interconnected offshore wind parks, but also when designing support schemes, so that the investment incentives can be upheld and investors be potentially compensated for adverse effects from additional interconnection options.

In Paper F, we adopted a real options approach to analyse investment decisions. Combining several uncertainty factors into a single stochastic process, we created a mathematical model that can provide closed-form solutions for optimising investment timing and capacity choice for wind energy projects. Concretely analysing an offshore wind park in the Baltic Sea and the Nordic electricity system, we compared FIT, FIP and TGC schemes. We found that, depending on the stochastic characteristics of the underlying processes, a TGC typically required an up to 3% higher investment threshold than a FIT. The FIP lies typically in between the other two schemes. The faster deployment in the FIT scheme (stemming from lower investment thresholds) comes at the expense of up to 17% smaller project sizes (if the capacity limit is not reached). Our approach provides an easily and quickly applicable tool for testing the effects of different policies and support levels on concrete investment decisions and inherently incorporates the important aspect of strategic flexibilities that private investors have when facing investment decisions.

In Paper G, we took the investigations of the preceding papers one step further to also provide a comprehensive framework for evaluating policy strategies in terms of their risk implications. In Papers B, C and D, we have identified required support levels under different support schemes. These insights are certainly important for policy makers when designing the support schemes to ensure that the desired investment incentives are given. But they do not contribute to assessing the desirability of certain support instruments. In Paper G, we therefore explored if the different risk implications matter in terms of social welfare and efficiency and how controlling risk exposures can contribute to achieving a transition of the energy system towards sustainability. We found, using the framework of transition theory, that energy transitions are best analysed in two phases, a first phase with focus on growth of niche technologies and a second phase with focus on integration. Each phase needs their own specific policies. In the first phase, it can be beneficial to use policy instruments that reduce risk for private investors, such as feed-in tariffs, and to create an enabling environment for the new technologies. This is crucial in effectively triggering an energy transition. Moreover, we found that this can be done without

compromising on cost-efficiency. In the second phase, policy focus shifts towards system and market integration of the new technologies into the regime. Targets for renewable deployment may shift from being minimum levels (so that implicitly, a policy that delivers maximum deployment is considered effective) to being exact targeted levels (so that only those policies are considered effective that have control mechanisms in place for both under- and over-development). Total support costs and windfall profits for RES-E producers may become a public acceptance issue. Here, policies that focus on system and market integration and allow for a gradual increase of risk exposure, can be successful strategies. The understanding of risk implications of support policies and the knowledge about how to steer investment incentives into the desired direction becomes even more important in the future when moving towards systems with very high shares of RES-E.

## 4.2 Discussion of results

In addition to the methodological discussion in Section 3.3, this section compares and discusses the results of the papers and sets them into a broader context.

**Precondition for the analysis.** The starting point of analysis in this dissertation is that support schemes exist in a national context. This is the case in all European countries (see Paper A). In Section 2.1 and in Paper G, we shortly discuss some economic reasoning behind the use of RES-E support schemes and specify related research. The focus of this dissertation is, however, not on answering the question if support schemes shall be applied or not. It rather deals with finding the optimal application strategy for RES-E support, acknowledging a predefined policy goal (such as the transition to a sustainable energy system) and a pre-existing regulatory and policy regime. We therefore e.g. analyse the switching from one support instrument to another. Such an approach could be criticised as being too narrow to provide comprehensive conclusions on optimal policies to be employed. This is undoubtedly correct. However, a large body of literature already exists dealing with the question of which policies are applied best in which situations, both from economic and other perspectives. On the other hand, there is a research gap in quantitative analysis incorporating risk implications that can help policy makers in improving their decisions on concrete support options. This dissertation focuses on the latter, acknowledging the trade-off between being able to make comprehensive conclusions and providing specific policy results.

An implicit assumption in this dissertation is also that policy changes are driven by policy makers' efforts to make their national schemes more successful, in terms of making them both more effective and more cost-efficient. The results from the empirical analysis in Paper A suggest that this indeed is a main driver of policy changes and of the convergence that can be observed in Europe.

**Quantitative estimations of risk implications from support policies.** In several papers, we made a quantitative estimation of the implications of exposing investors to more market risk in terms of required returns and support levels. In particular, we compared FIT and FIP schemes. In Section 3.3, it was already discussed in how far the methods and assumptions are comparable between the papers. Turning to the results, we have calculated differences in required support level between FIT and FIP of 5-10 EUR/MWh (in Paper B), 7.1 EUR/MWh (in Paper C), and 4.3-5.9 EUR/MWh (in Paper D). In all analyses, the FIT required lower support levels as compared to the FIP, due to a lower exposure of investors to market risks. One can conclude that the computed difference is rather similar in all three analyses. The level of detail and refinement increases along these three papers, so this could indicate that the first analysis in Paper B might have overestimated the difference somewhat. On the other hand, the assumptions also varied, e.g. the model in Paper D is calibrated to the German market (with comparably high required support levels), whereas Paper B is based on a Danish case (with lower required support levels). Overall, the results are in line with De Jager and Rathmann (2008), who estimate that policies which create stable and predictable cash flows (such as FIT schemes) can reduce the financing cost of RES projects by 10-30%. This corresponds to approximately 3-8 EUR/MWh when applied to the support levels in our analysis. The quantification of such differences in required support levels is important for policy makers who e.g. consider switching from an existing support instrument to a new one, especially from FIT to FIP. The support levels should then be adjusted accordingly in order to avoid insufficient investment incentives on the one hand and windfall profits on the other. We have argued that especially the switching from FIT to FIP schemes becomes increasingly important in Europe, both because of recent trends (Paper A) and because of the upcoming ascent of energy transitions into their second phase (Paper G).

**Desirability of policy instruments.** We have revealed several dominant trends in the use of support instruments in Europe (Paper A), but we have not analysed any causes these trends may have had, or if the trends are desirable or not. However, informed policy making relies on the understanding of the desirability of the identified trends and if these trends shall be re-directed or steered in certain ways, e.g. through intervention from national or EU-level.

Moreover, in Papers B-F we have not discussed which of the compared policy instruments actually are desirable from a societal perspective. We have merely quantified the differences in required support level. However, a lower required support level does not necessarily mean that a scheme is more effective, and neither that it is more cost-efficient for society (see the welfare economic discussion in Paper G). As discussed in Section 2.3.1, the desirability of a support instrument depends heavily on the policy goals and the status of the energy system. We have taken this question up in Paper G, where we set certain developments in relation to the phases of an energy transition and identify successful policy strategies. We concluded that especially in the first phase of new technology introduction, market forces alone cannot deliver the desired result of an energy transition, especially when considering the complex policy objectives often entangled in such managed transitions. In order to overcome

initial inertia of existing systems, risk-reducing support instruments (typically FIT) are important, as they seem best suited to trigger crucial deployment of RES-E in an early phase. This conclusion is in line with e.g. Mitchell et al. (2006) and Butler and Neuhoff (2008).

Furthermore, the desirability of policy instruments can also be influenced by specific design choices or by combinations of different policies into policy packages. Requirements of ‘next-generation policies’ for energy systems with high shares of renewables are quite different to today’s focus on increasing deployment, and demand more emphasis on finding the ‘correct’ support level for specific technologies, on market and system integration, and especially also on policy ‘safeguards’ that help controlling cost and volume of support schemes. This finding is in line with Miller et al. (2013).

**Focus on implemented, national policies.** All analyses in this dissertation are based on implemented policies. Focus is thus on outcomes only, and not on policy processes. Intended policies, planned policies, and policy decision making procedures in general are not taken into consideration. In reality, the applicability of certain support schemes, or even support levels within support schemes might depend on a number of such procedural factors, like regulatory and democratic processes, lobbying influences, policy making culture etc. (see e.g. Böhne (2011) on differences between national regulatory cultures and EU energy regulations). Moreover, the enforcement of policies might be prohibited or delayed. However, since the focus of this dissertation is on micro-economics and quantitative analysis of energy policy, none of this has been considered.

The analyses focus on national level only. It was reasoned above why this is a valid focus in the current policy making environment in Europe. However, for the future, it can be expected that national policy making will be more and more influenced by Europeanisation. This already becomes apparent in the discussion about the opening up of support schemes to electricity production from abroad, or about the use of cooperation mechanisms to set up joint projects or joint support schemes (see EC, 2013; and EC, 2014). This will become very relevant to investigate in the near future.

### 4.3 Summarised contributions of the dissertation

This dissertation contributes to the existing scientific body in two ways: It advances several aspects in the modelling of stochastic effects and risks for policy analysis. It also provides concrete results that can support policy makers’ decisions.

**Contributions to model development.** This dissertation contributes to model development through the creation of partial risk models for policy analysis. It comprises innovative application of existing approaches, such as the mean-variance approach, for comparative analysis of policy instruments. Also, certain stochastic pro-

cesses are adapted for the specific problems at hand. In particular, a tailor-made model for stochastic line failures on offshore interconnectors has been formulated. We developed an innovative approach on multi-year liquidity management to avoid financial distress in a firm in order to capture unsystematic risk effects in a cash flow analysis. Finally, we have formulated a real options model that innovatively includes capacity constraints in the optimisation of investment timing and capacity choice. To our knowledge, we are the first ones to have employed such an approach with capacity constraint for investment decisions on renewable energy projects.

**Contributions to policy analysis.** This dissertation brings together policy analysis with the quantitative modelling of risk. By adopting a micro-economic perspective, we have derived results that are crucial for the understanding of risk implications of support policy designs. These results can assist policy makers in making informed decisions about introducing support schemes, or about switching between different support instruments. They also help choosing the specific support levels necessary so that adequate investment incentives are given. By making specific cases, we showed the magnitude of the risk implications for offshore wind in Denmark and Germany, and thus illustrated that risk is a real issue that should not be neglected in policy decision making.

## 5 Conclusions and outlook

The research undertaken within this dissertation has sought to answer the research question of how risk implications of RES policy instruments can be integrated into policy design, so that the policies provide adequate investment incentives. The above descriptions and discussions have given an overview of how Papers B-F answer this research question based on quantitative, case-based analysis. It can be concluded that rather simple and easily applicable models can be developed that inherently acknowledge risk implications in investment considerations, i.e. by Monte Carlo simulations on stochastic input variables in combination with a cash flow approach, by using a mean-variance approach and by real options analysis. The results of these quantitative models give direct answers on the expected investment behaviour under different support instrument designs and on the differences in required support levels. Furthermore, it was asked if the consideration of risk implications in policy design can make overall energy policy more successful. We have answered this question in our analysis in Paper G, adopting the perspective of energy transitions. We conclude that policy designs that reduce risk exposure of investors are required to manage transitions to a sustainable energy system effectively and efficiently, especially in the first phase.

This thesis constitutes a step forward in the research on risk implications of renewable energy support policy. Quantification of risk effects of policy choices is still

a under-represented field in energy research as a whole. This might be due to the fact that it requires both insight into financial theory, stochastic modelling and a good understanding of the functioning of energy markets as well as energy policy instruments.

The research undertaken within this dissertation has contributed to closing the research gap in the area of model development, through creation of partial risk models for policy analysis, through adaptation of certain stochastic processes (such as for line failures), and through innovation in real options application for energy. It has also contributed to supporting policy decision making through concrete and tangible results for specific cases that transparently demonstrate the consequences of certain policy choices, such as switching from FIT to FIP schemes.

A final conclusion from the work carried out in all papers is that ‘standard’ cost-benefit analysis is not sufficient for well-informed policy design, or even for the choice between support instruments. Risk aspects are a decisive factor, and an appropriate treatment of risk aspects will almost always include the handling of stochastic processes and yield results that have probability distributions. The calculation of levelised cost of energy might seem alluring to some policy makers due to the simplicity of the approach, but using this as a basis for determining support levels often means ignoring risks effects, and this might lead to undesired investment behaviour. Instead, policy makers should make use of the tools and analysis available that treat risk aspects inherently, such as those provided within this dissertation.

Considering risk implications of policy instruments, it can be concluded that those policy instruments that reduce exposure of investors to market risks generally require lower support levels. Reducing risk can also lead to more effective renewables deployment, especially in the first phase of an energy transition. FIT schemes seem best suited for this in most situations, but this does not necessarily have to be the case. When an energy transition moves into a second phase, in which renewables have reached a significant market share and system and market conditions have been adapted to this new situation, also the policy goals change and renewable support policies should be adapted to include more competitive and market-based elements.

The research presented in this dissertation paves the way for several aspects of future research activity. First, the methods developed here can be applied to different real-life problems. By modifying them slightly, analysis in a much broader scope could be undertaken, e.g. for other RES-E technologies (such as photovoltaics), for different geographical regions (such as markets in Southern Europe or other world regions), for other energy sectors (such as the heat or gas sector), or even other industry branches with similar investment decisions. Second, the models can be further advanced with a number of potential improvements, e.g. in terms of the complexity of modelling (such as the stochastic processes), the scope (i.e. balancing markets could be included), and the design specifications of policy instruments analysed. In particular,

more focus could be placed on price caps and floors within support schemes, or on competitive support allocation systems. In the near future, also the Europeanisation of RES-E support should be investigated in more detail, e.g. through the analysis of consequences from opening up the support schemes to production from abroad.

This dissertation provides an informative basis for policy decision making. It does not develop a comprehensive framework for decision support, though. Building upon the insights, models and results from this dissertation, such a comprehensive framework could be developed in the future.

Finally, the results presented here show clearly that risk implications of RES-E support policies have a decisive impact on investment decisions in the energy system. Currently, energy systems models rarely model such differences in incentives. The insights from this dissertation can with benefit be integrated into energy systems modelling, so that they better reflect actual decision making.

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## Part II: Papers A to G

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PAPER A

# Renewable energy policies in Europe: converging or diverging?

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**Abstract**

*Nations today are urgently challenged with achieving a significant increase in the deployment of renewable energies. In Europe that need has given rise to a debate about the most effective and efficient support strategy. Whilst the different interests debate whether full European harmonisation or strengthening of national support policies for electricity from renewable energy sources (RES-E) is the best way forward, individual national support schemes are rapidly evolving. This study investigates how the EU Member States have applied support policy types over the last decade. By identifying predominant developments in the application of feed-in tariffs, premiums, tradable green certificates, tax incentives, investment grants, and financing support for specific technologies (wind, biomass, PV), this study shows that Europe is currently experiencing certain tendencies towards a 'bottom-up' convergence of how national policy-makers design RES-E policy supports. While some outliers remain, the policy supports of most countries become more similar in the policy types applied (dominance of feed-in tariffs) and in their scope of implementation (differentiation for installation sizes and 'stacking' of multiple instruments). These trends in national decision-making, which show tendencies of convergence, could make an EU-driven 'top-down' harmonisation of support either dispensable or at least (depending on the agreement) less controversial.*

**Keywords:** Renewable energy policy; Harmonisation; Europe

## A.1 Introduction

A significant increase in energy production from renewable energy sources (RES) is required in Europe in order to achieve emission reductions and other targets, such as related to security of energy supply. In 2009, the Member States of the European Union agreed to legally binding national targets for renewable energy in 2020 (Directive 2009/28/EC). The national targets comprise all energy sectors, meaning that they can be achieved by a combination of the use of renewable energy sources to produce electricity (RES-E), heat/cooling (RES-H) and transportation (RES-T).

In order to achieve the targeted 20% renewable energy production in Europe, significant investment in new renewable projects is required. De Jager et al. (2011) and Ragwitz et al. (2011b) estimate that the annual investment volume would have to be 60-70 billion Euros, compared to the current annual investment of 20-53 billion Euros. The European energy markets currently do not trigger sufficient investment levels, even with the financial supports available from policy schemes in all Member States. Due to a combination of cost of renewable technologies and achievable market returns, it is not expected that the European renewable targets for 2020 will be achieved without strengthened political support (Ragwitz et al., 2011a, p.13; Klessmann et al., 2011).

As required by the EU (Directive 2009/28/EC), every member state has elaborated its own pathway for achieving the target. These pathways were published in the form of National Renewable Energy Action Plans (NREAP) between July 2010 and January 2011 (Beurskens and Hekkenberg, 2011, p.28). The individual EU countries apply a variety of different policy supports for renewable energy sources. Table A.1 shows the most common policy types implemented in the EU.

**Table A.1:** Major RES support strategies implemented in the EU, status: August 2011

	Abbre- viation	Number of countries applying the scheme		
		RES-E Electricity	RES-H Heat/Cool.	RES-T Transport
Feed-in tariffs; Guaranteed prices	<i>FIT</i>	21	-	-
Feed-in premiums; Production premiums	<i>FIP</i>	7	3	-
Tender schemes	<i>TND</i>	5	2	-
Quota obligations, Building obligations	<i>TGC</i>	6	8	18
Investment grants	<i>INV</i>	20	25	11
Fiscal measures (tax incentives etc.)	<i>TAX</i>	13	12	22
Financing support (loans, etc.)	<i>FIN</i>	9	4	-

Sources: based on data from de Jager et al.(2011, p.27-34), Ragwitz et al. (2011a), Winkel et al. (2011), European Commission (2011a)

Of the three renewable energy sectors, RES-E has experienced the most diversified application of support strategies and has also the longest history of support. The first EU countries to introduce specific policy support for RES-E were Denmark (1979), Portugal (1988), Germany (1989) and the United Kingdom (1989/90). Today, all EU countries have implemented policy support for RES-E. According to the pathways described in the NREAPs, 33.9% of the electricity consumed in the EU will be produced from renewable energy sources in 2020, with a range from 5% in Estonia to 71% in Austria. As discussed above, strengthening of financial support for RES-E is an important factor in achieving these targets.

### A.1.1 The research interest

In the European Union, two general approaches are being discussed about how to organise policy support for RES-E. One approach is a fully harmonised support system, where the policy types are decided top-down and implemented alike in all Member States. Prior to finalising Directive 2009/28/EC, such a harmonisation of RES-E support in Europe was concretely discussed in form of a pan-European quota

obligation scheme with tradable green certificates (TGC). However, ultimately it was not implemented in the Directive (Rowlands, 2005).

A second approach is that all EU countries have an independent choice of policy types and support schemes, so that the RES-E supports develop in a more ‘bottom-up’ approach. This is the current situation in Europe. Here, the European Commission is responsible for monitoring the activities of the Member States and for assessing the established support policies.

More recently, regional concepts, where two or more countries cooperate on a cross-border policy scheme, have increasingly come into discussion. Some early cooperations between countries are starting to be implemented, for example between Sweden and Norway.

Whilst the debate between supporters of full EU harmonisation and supporters of full national independence of RES-E support is ongoing, the national support schemes for renewable energy are rapidly evolving. One possibility is that ‘best practices’ emerge along with the rapidly evolving national support schemes, and therewith policies may naturally become more similar across the individual Member States. It could then be spoken of a ‘bottom-up’ convergence of RES-E support in Europe, whereby a ‘top-down’ harmonisation would become either dispensable or at least less controversial, if it coincided with the de facto ‘bottom up’ convergence. The European Commission sees an immediate need for a convergence of national support schemes. Referring to the EU Energy Strategy, they note that “a greater convergence of national support schemes to facilitate trade and move towards a more pan-European approach to development of renewable energy sources must be pursued” (European Commission, 2011b, p.11).

This study analyses the trends in the way EU Member States are applying RES-E support policies to determine whether the national support schemes are in fact converging or diverging. In this respect, the concept of ‘convergence’ is understood in the notion of similarity in the decisions of policy-makers regarding the *policy types* to implement for RES-E, such as the choice between feed-in tariffs, tenders or quota obligations. More specifically, it is analysed if there has formed a common European understanding, or ‘best practice’, of what policy types to use and how to implement them (e.g. for certain technologies or installation sizes). If the choices of policy types and their scope of implementation are increasingly similar, there can be spoken of a ‘convergence’ of policy support for RES-E.

This is only one of several possible approaches or understandings of convergence. Ragwitz et al. (2011b), for example, argue that a gradual convergence of the key *properties* of policy instruments, including the use of caps and quantity control in feed-in tariffs, a technology specification in quota systems and such, can be observed

(pp.38-42). While this analysis is certainly relevant, it can be argued that the choice of *policy type* itself, i.e. the choice of a feed-in tariff over a quota obligation, rather than the design of its properties, is one of the most significant factors in political decision making, and one which either fosters or hinders the potential for cross-border cooperation and harmonisation. Countries that make similar decisions regarding the policy types of their support systems, e.g. those which apply quota obligation schemes, will have a broader basis for cooperation than countries with completely different support systems. The dominance of certain ‘best practices’ in terms of policy types could lead to more and closer cooperation, and the introduction of (partial) joint support schemes would require a less radical change. The subject of investigation in this article is therefore the choice of policy types.

## A.2 Method

As a basis for the analysis, data on the application of policy types for RES-E support was collected from each member state of the European Union. The RES-E policy supports of all 27 countries that are now member of the European Union were analysed from their individual beginnings until the latest status in mid 2011. The focus years are 2000, 2005, 2010 and, because of the very dynamic nature of the subject, changes that occurred between 2010 and 2011 are also taken into account.

The policies were analysed on a detailed level, specific for each policy type and RES technology in each country. Data and background information were drawn from primary and secondary literature on the subject. Major sources for the analysis have been the European Commission (2011a), Haas et al. (2011), Ragwitz et al. (2011), ECN (2011), Winkel et al. (2011), Ragwitz et al. (2011), as well as policy documents from each of the 27 EU countries, mostly obtained through the website from the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety in Germany, BMU (2011).

The data analysis was based on the following criteria: In order to appear in the statistics, a support scheme must be decided, implemented, in force, and open for new RES-E projects in the respective year. Tradable Green Certificate schemes must have a functional trading platform. Announced schemes, schemes with a legal basis but without concrete implementation, and schemes without sufficient budgets were not considered. Schemes that had no funding in the respective year or were closed for new projects were excluded from the overview.

This study includes all developments until July 2011, support schemes for single technologies and/or for a limited target groups, as well as grants that make use of EU funds. As a result of these and other differences in the treatment of the underlying

data, the statistics here are somewhat different from what the European Commission and others presented earlier (European Commission, 2011b, p.10; Ragwitz et al., 2011b).

It should be noted that when a new policy scheme is implemented to replace an existing one, e.g. when a TGC replaces a FIT scheme, the existing RES-E projects often continue to be supported under the old scheme, alongside the new one - this aspect is, however, not in focus of the analysis at hand.

### **A.3   RES-E policy types applied in Europe**

Policy supports for investment in RES-E are typically based on a combination of different policy types. The policies can be differentiated according to their characteristics such as regulatory or voluntary, direct or indirect, investment-focused or generation-based, and more. Haas et al. (2011) described the categories and their differences in detail.

Here, it is sufficient to focus on policy types that are applied as part of major support schemes in EU Member States. These are direct, mostly regulatory support policies. The following policy types are distinguished:

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<b>Major support instruments</b>
Feed-in Tariffs (FIT)
Feed-in Premiums (FIP)
Tenders (TND)
Quota obligations with tradable green certificates (TGC)

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<b>Supplementary support instruments</b>
Investment grants (INV)
Fiscal measures (TAX)
Financing support (FIN)

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In the following section, the different policy instruments are described and the criteria for their categorisations are explained.

**Feed-in tariff (FIT)** schemes have several elements: priority dispatch to eligible generation, long-term perspective, and guaranteed prices. The price is usually either guaranteed for a specific period (a number of years, as in Germany), or for a pre-determined amount of production (e.g. the first 10 TWh, as in Denmark for certain projects).

In most implementations of FIT (especially earlier ones), the producers of renewable electricity are exempt from market participation, and receive the guaranteed price

by delivering the power to an obliged off-taker. These FITs are sometimes called ‘all-inclusive’ tariffs. Here, an institution (often the transmission or distribution system operator) is obliged to off-take the electricity at the guaranteed price, market the electricity and pass on the cost of the scheme, most commonly to electricity consumers, e.g. via public service obligation charges added to the electricity bill.

In some (more recent) applications, the price guarantee is granted in the form of a variable add-on to the market price. Here, a specific target price is determined as the total tariff the producer of renewable electricity should receive. The FIT is paid out as the difference between the target price and the market price. Denmark was the first country to establish such a scheme for wind power in 2000. The categorisation of target-price FIT in this analysis is in line with (amongst others) Couture et al. (2010), where target price FIT are referred to as ‘sliding’ premium-price FIT (p.vii). In other studies, target-price feed-in tariffs have been categorised under feed-in premiums, for example in Winkel et al. (2011). There is indeed a fine line between the two categories, as in both instruments, market price add-ons are being paid. The distinction is made here based on the existence of a target price (hence the name), which is typical for FIT in diminishing market risk for the producer, whereas FIP schemes typically only guarantee the add-on amounts and thus do not reduce the underlying market risk.

The following implementations of Feed-in tariffs currently exist in the EU:

1. **Fixed feed-in tariff:** One tariff is determined for each technology group and changed only with amendments to the regulation (examples are Germany, Portugal, Lithuania).
2. **Time-dependent feed-in tariff:** Two to three different tariffs (day / night, peak / off-peak) are pre-determined for each technology group and changed only with amendments to the regulation (examples are Spain for hydro and biomass, Hungary)
3. **Indexed feed-in tariff:** Tariffs depend on specific market indicators such as the exchange rate to the Euro or the price of natural gas, and are therefore not certainly known at the time of investment (an example is Latvia)
4. **Adjusting Feed-in tariff:** Tariffs are not strictly fixed from time of installation, but amendments in the regulation may also apply for existing projects (examples are Bulgaria and Czech Republic)
5. **Target-price Feed-in tariff:** The tariff is guaranteed as target-price and paid out in the form of an adjusting add-on to the market price so that the market price is topped-up (or reduced) to the guaranteed price. Those prices can be pre-determined for technology groups under the regulation or subject to project-specific agreement e.g. through tenders (examples are Denmark and from 2012 onwards also Germany). The rationale behind using target-price Feed-in tariffs is typically to facilitate the market integration of the electricity



production under FIT while still providing protection from market risk through the guaranteed target price. Target-price Feed-in tariffs that are based on negotiated prices are also referred to as *Contracts for difference* (CfD). Currently, the UK is in the process of establishing such a scheme, with the detailed set-up yet to be determined (for up-to-date information, see Department of Energy & Climate Change, 2012).

**Feed-in premiums (FIP)** are guaranteed premiums paid out as fixed add-on to the market price. Generally, a producer of renewable electricity receives a premium per unit (MWh) in addition to the proceeds of selling the power on the free market. As with FITs, the premiums are generally guaranteed for either a fixed period (as in Italy) or a pre-determined production (as in Denmark, for example for 12.000 full load hours).

The following implementations of the guaranteed premium currently exist in the EU:

1. **Fixed Feed-in premium:** A fixed premium is pre-determined by regulation for each eligible technology group, and changed only with amendments of the regulation (examples are Denmark, Spain, Estonia, Slovenia)
2. **Adjusting Feed-in premium:** Tariffs are not strictly fixed for projects, but amendments to the regulations may also apply for existing projects (an example is the Czech Republic). Premiums can also be variable dependent on certain indicators, such as in Spain, where premiums vary on the basis of per-hour market prices, providing a floor and cap for the income of a producer of eligible RES-E. The rationale behind providing caps and floors is typically to protect producers from extensive risk exposure towards low market prices, while limiting the risk of over-compensation for high market prices.

It should be noted that several other studies, including Couture and Gagnon (2010), treat feed-in premiums as a subcategory of Feed-in tariffs.

**Tenders (TND)** are typically used in combination with another policy type. In the specific combinations, quite distinct characteristics arise for authority planning as well as for investor risk. In a tender process, the responsible authority launches calls for tenders for specific projects (or specific groups of projects) with defined amounts of capacities. Potential investors then compete to win the opportunity to develop the project by giving their bid for the required support level and several other specifications (as e.g. specific timing of the project, grid positioning, and environmental impact). The most attractive bid, determined by a low requested support level and favourable other specifications, wins the tender. There currently exist two different implementations of tender processes in the EU:

1. **Tenders for fixed Feed-in tariffs** (an example is France)

## 2. Tenders for target-price Feed-in tariffs (an example is Denmark)

In 1994 in Ireland (in AER I), tenders for investment grants were used. This was however discontinued due to limited success of the model, and already in the preceding bidding round AER II in the same year, the tender was re-designed to bidding for fixed feed-in tariffs. The UK also implemented a tender - the Non Fossil Fuel Obligation (NFFO) - in 1990, transferring to a TGC in 2002.

**Quota obligations with Tradable Green Certificates (TGC)**, also called Renewable Portfolio Standards (RPS) with Renewable Energy Certificates. In TGC schemes either producers or suppliers of energy are obliged to have a specific share of renewables in their portfolio (the quota obligation). Thus, in contrast to FIT and FIP, where price levels are controlled by the policy-makers, TGC are referred to as 'quantity'-control instrument. Certificates that represent a certain production from renewables (e.g. 1 MWh of 'green' electricity equals 1 TGC) are used to demonstrate compliance with the quota obligation to the authorities. These certificates can be freely traded on the market and a market price materialises for the certificates in each compliance period (e.g. one year). TGC schemes can be *uniform* or *differentiated* in the granting of certificates per generated unit of electricity. If the scheme is uniform, all technologies receive the same amount of certificates per generated unit of electricity (examples are Sweden, Belgium, Poland). If they are differentiated, certain technologies receive more certificates per generated unit and others less. The latter is called 'banding' of the certificates (examples are UK, Italy, Romania). In some applications, certificates can be transferred from one compliance period to the next, they are 'bankable'. This increases the stability of the certificate market and can help making the system more efficient (an example is Sweden).

Not included in the analysis are voluntary green certificate trading schemes of the type "guarantee of origin" which do not impose a quota obligation and a penalty of non-compliance.

**Investment Grants (INV)** are financial supports granted by governmental (and European) institutions to investors in renewable energy projects in the form of non-reimbursable payments at the construction phase of a project. Most investment grants are paid out for the construction of a project, so the amount of RES-E being generated from the project is not directly targeted. Often the payments are however subject to e.g. the successful completion and grid connection of a project and the fulfilment of certain performance standards. Most of the European countries have implemented some sort of investment grant scheme for RES-E. The grants range from 5% to more than 70% of the total investment cost.

**Fiscal measures (TAX)** comprise mainly direct fiscal support. Indirect tax incentives, such as eco-taxes on fossil fuels or CO<sub>2</sub>-taxes, are not specifically considered as

support instrument in this analysis because it is assumed that they are implemented solely to internalise external cost. There are several direct fiscal support measures implemented in the EU:

1. **Income tax reliefs** are granted either as partial or full relief, directly (as for example in Belgium) or through enhanced capital allowances and other favourable depreciation rules on the investment cost (as in UK, Netherlands).
2. **Electricity tax reliefs** are granted in some countries where electricity generators are subject to electricity taxes (as for example in Poland and Latvia).
3. **Reduced value added tax (VAT)** can be applied on sales from eligible technologies (as for example in France and Portugal).
4. **Net metering for own consumption** can have the effect of tax relief from all taxes imposed on energy consumers, generally energy taxes and VAT. RES-E production for own consumption benefits in these cases from such tax reliefs (as for example in Denmark for small house installations).

**Financing support (FIN).** This category depicts a range of support instruments in the financing area. Regulation No 1828/2006 of the European Commission (2006, Article 43/1) defines such instruments within the context of repayable investments (in contrast to non-reimbursable grants) as ‘financial engineering instruments’.

These can be reimbursable equity investments or provisions of venture capital by governmental institutions, but also debt financing, e.g. in form of low-interest loans to renewable projects by a governmental financial institution (such as the KfW in Germany). More recently introduced instruments are Mezzanine finance (equity/debt hybrids), equity guarantees, loan guarantees and securisation products (e.g. provision of credit default swaps), amongst others provided by the European Investment Bank (EIB). These instruments are designed to help the investors of renewable projects to access the capital market and to obtain financing at adequate terms, making more investments possible and therewith adding to renewable growth at low support cost.

## **A.4 Trends in the development of support systems in Europe**

Some major trends in the development of national support policies for RES-E in the European Union are investigated in this section. A very obvious and general trend is the rapid development of RES-E policy schemes. Most support schemes are being changed and improved on a continuous basis. Each year, new schemes are implemented and others are amended in many countries of the European Union. Three areas are investigated for trends in more detail:

1. Establishment of renewable support schemes
2. Differentiation of support schemes
3. Combinations of support schemes

The first area of investigation refers to when RES-E support policy schemes are established in the different countries, which types of policies are applied and how that develops over time. The second area refers to the extent to which the application of policy types is differentiated and specialised for certain technologies and installation sizes. The third area of investigation refers to whether and how different policy types are combined to function together in a single country.

#### **A.4.1 Establishment of renewable support schemes**

Prior to 2000, fifteen countries in the EU have provided explicit policy support for RES-E, which were also the fifteen EU Member States at that time. In the following years, all other countries which are now EU Member States, have introduced RES-E support schemes, so that since 2007 explicit policy support is available for RES-E in all EU countries. This comprehensive development was largely driven by a pan-European policy framework, which amongst other things included the suggestion for a target share of renewable energy already in 1997 (European Commission, 1997), and the recognising of the need for policy support for renewables in the Community guidelines for State aid for environmental protection (European Communities, 2001, p.3).

Table A.2 provides an overview of how EU countries have provided RES-E policy support over the past decade.

Only a very limited number of countries strategically provided investment grants or fiscal measures as their primary support instruments. Finland was in fact the only country strategically opting for tax exemptions as major instrument for most renewable technologies until it also implemented a FIT scheme in January 2011 (subject to EC approval), after a FIT for peat in biomass plants had been in place since 2010. In other countries INV, FIN and TAX were (temporarily) the only support instruments mainly due to late or delayed implementation of other major measures, for example in Cyprus, where the in 2003 decided FIT scheme was not enacted until 2009.

**Table A.2:** RES-E support policies in EU countries 2000-2011

	Number of countries that have implemented the scheme			
	2000	2005	2010	2011
Provision of renewable support	15	24	27	27
Provision of major support schemes FIT, FIP, TND or TGC	10	22	27	27
Provision of INV, TAX or FIN as primary support	4	2	1	-
<b>Major support schemes</b>				
Feed-in tariffs (FIT)	7	16	23	21
Feed-in premiums (FIP)	-	4	7	7
Tenders (TND)	2	2	6	5
Quota obligations with TGC	1	6	6	6
<b>Supplementary support schemes</b>				
Investment grants (INV)	5	10	20	20
Fiscal measures (TAX)	9	10	12	13
Financing support (FIN)	4	4	9	9

#### A.4.1.1 Major RES-E support instruments

As of 2011, every EU country has implemented at least one of the major support instruments FIT, FIP, TND or TGC. Amongst the major support instruments, FIT schemes are clearly dominant. They have not only the highest share of countries implementing it (from 50% in 2000 to 85% in 2010), but also the highest growth rate in application: Between 2000 and 2010, each year almost two new countries introduced a FIT scheme on average. In the year 2011, FIT have experienced a slight ‘pull-back’ as the Slovak Republic and Estonia have discontinued their FIT, both to the favour of a FIP scheme remaining in place. This is discussed further in Section A.5.

Denmark was the first country to implement FIP payments in 2003 as fixed premium for new onshore wind installations. Recently, FIP schemes have come more and more into focus, and have reached a maximum of 7 implementations.

Complete re-orientation of policy schemes in a country is relatively rare. A few instances can be mentioned: In 2002, the UK switched from a tendering scheme (under the Non-fossil fuel obligation) to a TGC scheme and is currently considering updating the RES-E support as part of the energy market reform, which includes the possibility of introducing the aforementioned FIT CfDs for larger scale renewable schemes, alongside the FIT for schemes under 5 MW (see Section A.3). Also Italy introduced a TGC scheme in 2002 after a period of FIT support. Austria switched, after a transition phase, from a TGC scheme (which was discontinued in 2002) to a FIT.

#### A.4.1.2 Supplementary RES-E support instruments

Only two countries (Ireland and Slovenia) have not implemented at least one of the supplementary support schemes INV, TAX or FIN. Amongst the supplementary support instruments, investment grants are with currently 20 implementations clearly dominant. They have also the highest growth rate having increased to 400% of the implementations in 2000. This is even a more significant increase than for FIT schemes.

Financing support (FIN) is becoming more and more significant having increased from 4 to 9 implementations. This development is of special interest in the analysis of RES-E policies from a European perspective since this support can actually rather easily be granted independently from countries and national support schemes. This is further discussed below.

#### A.4.2 Differentiation of support instruments

From the analysis above, it becomes apparent that there are many more policy schemes implemented in the EU than there are countries. This is partly due to the differentiated implementation of policy supports, so that specific policy instruments are applied for different parts of the RES-E production. The two most apparent differentiation options are investigated below, namely the technology type and the installation size.

Table A.3 shows the number of countries that have implemented the major policy types, differentiated for technologies and installation sizes. The classifications into ‘large’ and ‘small’ installation sizes are made technology-specific, taking typical sizes of PV, biomass, and wind power installations into account.

**Table A.3:** RES-E support policies, differentiated for technologies and installation sizes, status mid 2011

	Number of countries that have implemented the scheme in 2011						
	Photovoltaics		Biomass		Wind energy		
	small <sup>1</sup>	large	small <sup>2</sup>	large	small <sup>3</sup>	large	all sizes
Feed-in Tariffs	18	12	20	13	19	15	9
Feed-in Premiums	4	4	6	4	5	5	3
Tendering scheme	1	3	1	2	1	1	4
Tradable Green Cert.	5	5	6	6	6	6	5

<sup>1</sup>(<5MW); <sup>2</sup>(<50MW); <sup>3</sup>(<20MW)

For example, a size of 10MW is large for PV installations, but small for onshore wind power projects. A differentiation of offshore installations is not considered due to the generally large size of such commercial projects.

Also here, FIT schemes dominate the picture. The new aspect in the analysis relates mainly to their differentiated application. FIT schemes show a significant differentiation regarding the installation sizes: Significantly more countries apply FIT schemes for small installations than for large installations, and this is the case for all technologies. Not considering the special case of offshore wind (where most installations are large), we see a broad application of FIT schemes for small installations across all technologies, ranging from 18 countries for PV to 20 countries for biomass. Large installations are significantly less often supported with FIT schemes, ranging from 12 countries for PV to 15 countries for onshore wind. The differentiation for installation sizes is far more significant than for the technology itself.

There is a small tendency for tendering schemes to be applied to large installation sizes, especially for PV, where three countries apply TND schemes for large installations, but only one country also requires tendering rounds for (groups of) small installations. However, due to the low number of schemes implemented, no overall conclusions can be drawn. Offshore wind installations, with their typically large size, have a significantly different distribution of policy types than the other considered technologies. A higher share of the countries applies TND schemes (4 out of 17 countries that offer support for offshore wind).

### **A.4.3 Combinations of support instruments**

After having analysed the establishment of policy schemes and their differentiation according to technologies and installation sizes, a third area of investigation becomes possible: how the differentiated policy instruments are combined. The average number of support instruments per country is an indicator of the willingness of countries to combine several instruments in their policy support. Table A.4 shows that the average number of support schemes has increased significantly from one instrument per country in 2000 to three instruments per country in 2011.

**Table A.4:** Average number of support instruments applied per country in the EU, 2000-2011

Average number of	Number of instruments applied in a country			
	2000	2005	2010	2011
<b>RES-E policy instruments</b>	<b>1.0</b>	<b>1.9</b>	<b>3.1</b>	<b>3.0</b>
Major support instruments	0.4	1.0	1.6	1.4
Supplementary support instruments	0.7	0.9	1.5	1.6

There are two general ways on how support instruments can be combined. Firstly, two or more support instruments can be implemented in parallel, so that RES-E producers may choose their preferred type of support. This is mostly the case for FIT and FIP combinations. Secondly, different instruments can be made available for specific parts of the RES-E production (e.g. TND for offshore wind, or all projects below 12 MW are eligible for a FIT).

Table A.5 shows, how the different policy instruments are combined with each other in EU Member States. Only the most relevant and significant combinations are listed in the table. This analysis shows for example that of the 27 countries which have implemented a major support instrument in 2011 (see Table A.2), 17 countries apply only one major instrument, eight countries apply two and the remaining two countries apply even three major instruments. Out of the 21 countries that apply FIT (see Table A.2), five countries have combined them with FIP, and five others with TND.

**Table A.5:** Combinations of RES-E policy instruments implemented in EU countries 2000-2011

	Number of countries that have implemented the scheme(s)			
	2000	2005	2010	2011
<b>Major support instruments</b>				
One major instrument applied	10	18	14	17
Two major instruments applied	-	3	11	8
Three major instruments applied	-	1	2	2
Combination of FIT and FIP	-	3	7	5
FIT with an added TND process	-	2	6	5
Combination of FIT with TGC	-	-	2	2
<b>Supplementary support instrum.</b>				
One supplementary instrum. applied	9	10	13	12
Two supplementary instrum. applied	3	4	8	9
Three supplementary instrum. applied	1	2	4	4
Combination of INV and TAX	2	5	8	9
Combination of INV and FIN	2	2	6	6
Combination of TAX and FIN	2	3	6	6
<b>Major and supplementary instrum.</b>				
Combination of FIT and INV	2	6	16	15
Combination of FIT and TAX	4	6	9	9
Combination of FIT and FIN	2	4	8	8
Combination of TGC and INV	-	3	5	5
Combination of TGC and TAX	-	3	4	4
Combination of TGC and FIN	-	-	1	1



#### **A.4.3.1    Major support instruments**

The combination of major support instruments for RES-E is a rather recent phenomenon. In 2000, no country had implemented more than one major instrument. In 2010, the number was temporarily up to 13 countries applying at least two major instruments. Two EU countries even apply three major instruments. One of them is Denmark, which provides support for onshore wind and biomass in the form of fixed FIP, support for PV and other technologies in the form of fixed FIT, and support for offshore wind in the form of TND for guaranteed feed-in prices. The other country, Italy, has next to its general TGC scheme also implemented a FIT scheme for small projects (up to 1 MW) and a FIP scheme for solar power.

A parallel implementation is most commonly seen for FIP and FIT schemes, where FIP is the ‘additional’ instrument. Spain is since 2004 the most prominent example for a long-term parallel implementation of FIT and FIP. In some other countries, the two instruments are implemented in parallel for a period, before a transition is initiated. This can be seen for transitions from a FIT to FIP scheme, as in the Slovak Republic, where the FIT has been phased out in 2010 and only the FIP remains.

Most TND schemes are now tenders for guaranteed prices, which are obviously closely related to FIT schemes. In fact, most current TND schemes were introduced in addition to an already existing FIT scheme.

TGC schemes are prone to be used as sole major instrument, because the size of the certificates market is a success factor for the instrument (for example in relation to target setting, see Morthorst, 2000). However recently, TGC schemes were supplemented by FIT schemes, namely in Italy from 2008 and in the UK since April 2010. The combined use of TGC and FIT represents a shift in political decision making in the two countries, away from a support that is based on pure quantity-control (TGC) towards a more differentiated support including both quantity and price control (TGC and FIT).

#### **A.4.3.2    Supplementary support instruments**

A significant trend in the development of supplementary support instruments is the increasing number of countries who use two or even three supplementary instruments in parallel. In 2011, this reached a new maximum of 13 countries. All relevant combinations have increased over the last decade and there is no clear trend for certain combinations to become dominant.

### A.4.3.3 Major and supplementary support instruments

From the analysis of combining major support instruments, it is understood that the implementation of FIP and TND is very closely related to FIT schemes. Therefore, the focus is on TGC and FIT only in the following analysis. Conclusions for FIP and TND can then be drawn from the results related to FIT schemes.

From Table A.5, it becomes apparent that in absolute terms, the combination of FIT and INV is dominant, which is of course due to the dominance in the implementation of both the instruments. Relatively seen, the trend to combine a major instrument with supplementary instruments is equally significant for both FIT and TGC schemes. Currently, there is no TGC scheme where not at least one of the supplementary instruments is implemented in parallel, and there is only one country (Slovenia) where no supplementary instrument is available next to the FIT/FIP scheme. Financial support instruments (FIN) show the greatest difference in the application under a FIT or TGC scheme, respectively. They are almost solely implemented in countries that use FIT as major support instrument.

## A.5 Discussion and possible future trends

The above described analysis and its results can help to draw conclusions on some trends in the development of RES-E policy supports in Europe. The results should however be interpreted carefully, as the analysed data do not represent a statistically sufficient quantity for general conclusions. Nor were policy makers' intentions and planning taken into consideration - only those policy support schemes that were finally implemented have entered the database. It might bias the conclusions regarding a convergence dependent on policy decision-making whenever the implementation of 'decided' policies was prohibited or delayed by other factors, such as bureaucratic or other processes.

### A.5.1 Discussion of observed developments

There is a rapid development of RES-E policy supports. As was shown by the historical analysis, the RES-E support landscape in the European Union has changed a great deal in just one decade. It can be expected that much of the development is driven by policy makers' efforts to make their national RES-E policy support schemes more successful - that is, to make them more effective and efficient.

In that regard, many detailed studies have been conducted to assess the performance of either the policy support in one country or of a specific policy instrument in several countries (see for example Ragwitz et al., 2007; Jacobsson et al., 2009; Held et al., 2010; Ragwitz et al., 2011; Menanteau, et al., 2003, Morthorst, 2003). Many of these studies have presented policy recommendations and best practices for policy makers, which may have contributed to a pan-European understanding of which policy types to implement for the support of RES-E.

This section discusses whether the observed trends described in Section A.4 show characteristics of a convergence, and where there are exceptions from the rule. A precondition for a comprehensive development of RES-E policy support in Europe is the existence of support schemes in all countries. Since 2007, all of the 27 EU countries have implemented RES-E supports, and since 2010 all of them have provided support with at least one of the three major support instruments: FIT, FIP or TGC.

The first significant trend in the development of RES-E policy supports in the EU, shown in Section A.4.1, is the dominant use of price-control instruments (i.e. FIT or FIP), especially FIT. They are not only implemented in most countries, they also show the highest growth rate throughout the period. While TCG schemes experienced a small ‘boom’ in the early two-thousands, no new TCG scheme has been implemented after 2005. On the contrary, existing TCG schemes have lately been supplemented with FIT schemes for small installation sizes in the UK and in Italy. In mid 2011, there remain four ‘outlier’ countries that do not apply any form of price-control instrument. These are Belgium, Sweden, Romania and Poland.

Secondly, Section A.4.2 shows the differentiation of major policy types according to installation sizes. FIT are again dominant, especially for small installations. On average, there are 44% more countries applying FIT for small installations than for large ones, across all technologies. Some examples of specialised FIT for small installations are France (TND for large installations), Italy and the UK (TCG for large installations), as well as Slovenia (FIP for large installations). Other countries support only small installations of certain technologies, such as Hungary and Luxembourg. The results suggest that there has formed a common understanding amongst policy makers that price-control schemes are especially suitable for small installations. However, there are still several countries that do not differentiate their major support schemes for installation sizes, such as Germany (FIT for all sizes and technologies) or Sweden and Belgium (having implemented a single major scheme, i.e. TCG). Here, some sort of persistence seems to remain next to a common trend of convergence.

The third significant trend, shown in Section A.4.3, is that European countries have begun to apply multiple support instruments at the same time. This observation goes also in line with the above described trend to differentiate policy support. Countries apply now a whole range of different support policy instruments in combination (they

‘stack’ instruments) rather than having one major and/or supplementary instrument, which was still the norm in the year 2000. Denmark was at the forefront of applying multiple instruments and currently applies six of the seven investigated policy types. Also France, Portugal, Italy, Netherlands and Spain all apply four to five policy types in parallel, including at least two parallel major support instruments. Furthermore, certain combinations of support instruments are dominant: Especially FITs are used in combination with other major support instruments, especially FIP and TND, but also TGC in the UK and Italy. An outlier country seems to be Ireland, which currently has only one single instrument in place, namely FIT.

Based on these three trends, it can be concluded that there are certain areas, in which the national policy makers in Europe are making more and more similar decisions. This development could indicate that a bottom-up convergence is ongoing in the respect it is investigated here: Firstly, policy makers make more similar decisions in what policy types they implement, namely price-control instruments become more and more dominant. Secondly, they are also converging in how they are implementing the instruments, namely they use the instruments more differentiated and ‘stacked’. Especially FITs are applied most significantly for small installation sizes. The average number of policy instruments in a country has grown from one to three parallel instruments.

This analysis has however also shown that some diverse practices are persistent. There are countries that do not apply price-control instruments at all, and some countries do not differentiate or ‘stack’ instruments. What is revealed here are dominant trends, not comprehensive developments that include all countries. It cannot be concluded that (even if the current trends are followed further) the development of national policy supports would eventually culminate in completely comparable policy supports. One should rather expect an incomplete alignment of policy supports through such a bottom-up development, with some ‘outliers’ remaining. On the other hand, a ‘top-down’ harmonisation cannot guarantee a full alignment either. In Europe also some top-down developments show signs of partial convergence, as can be seen in the progress on the internal gas and electricity market and the number of ongoing infringement procedures (European Commission, 2011c).

It is still to be seen whether the differentiation and ‘stacking’ of policy instruments actually improves the effectiveness and efficiency of RES-E policy supports in the EU. Both positive and negative effects can be induced by combining different support schemes. For example adding an FIT scheme to an existing TGC scheme can foster investment from smaller investors (see Mitchell et al., 2006), but it could also decrease the market volume for certificates, which could make the TGC scheme less efficient.

The effect of combining major and supplementary instruments should also be investigated regarding the effectiveness and efficiency. For example, combining tax incentives with major operating-support schemes, or combining investment grants

with tendering schemes, could potentially produce severe overlapping and distorting effects, especially when not all project developers or investors can benefit from all schemes equally. It could e.g. occur that there exist restrictions for receiving grants for certain market players or that different companies have different qualifying tax bases in case of tax reliefs. Such distorting effects are not always investigated detailed enough at the time a new instrument is added to the RES-E supports in a given country.

This analysis identifies and describes trends in RES-E policy supports in Europe; it does not answer the question of what causes the observed trends. With a better understanding of the causes, it would be possible to discuss to what extent the increased use of combinations might be a transitional phenomenon related to different phases in RES-E policy support. In some countries, we can already now see a decline in certain combinations, such as in the Slovak Republic, where FIT and FIP were implemented in parallel for a period, before the FIT scheme was discontinued to the benefit of the FIP scheme.

The reason for transitioning from FIT to FIP schemes could lie in market integration issues. The higher the deployment of RES-E in terms of market share, the more important integration of RES-E becomes. Not all policy types are equally capable of integrating RES-E into the overall market. Fixed FIT schemes tend to route RES-E directly from the producer to the consumer, parallel to the market. In this case, producers of RES-E are not market participants and cannot directly respond to market signals, e.g. negative prices in case of over-supply. FIP schemes typically integrate RES-E fully into the market, so that producers of RES-E can respond to market signals. On the other hand, Ragwitz et al. (2007) show that FIP tend to have higher remuneration levels than FIT in order to compensate for the higher risk connected with the exposure to market prices (p.117). Market integration could thus be one underlying driver of the changes observed in the application of policy supports in Europe, and could account for the increasing use of FIP and target-price FIT.

In addition to the trends observed in the historical analysis, certain new developments, which will also have an influence on the development of national RES-E supports, are expected to become apparent in the near future. Two of them are described in the following section.

### **A.5.2 Future Trend 1 - Coordination of renewable support between countries**

Assuming that all EU Member States meet their renewable targets by 2020, and develop according to the paths laid out in their NREAPs, ten countries will have an RES-E share of more than 50%, while more than half of the European countries will

have a RES-E share of 35% or more (based on data from Beurskens and Hekkenberg, 2011; ECN, 2011). Achieving these deployment shares will require significant efforts to integrate the renewable electricity into the system.

As mentioned in the introduction, the European Commission has claimed that this integration will require the coordination of support across European countries. For this purpose, Directive 2009/28/EC introduces three options for EU Member States to cooperate in reaching their renewable targets. By making use of cooperation mechanisms, countries become more flexible in terms of how to reach their national targets.

The cooperation options introduced by the EC directive are (see Klessmann et al., 2010, p.4):

1. **Statistical transfers**, where renewable production is ex-post transferred from one country's statistics to another's, based on negotiated conditions,
2. **Joint projects**, where countries jointly set framework conditions for projects; this may include that one country provides support payments to a project in another country, and
3. **Joint support schemes**, where countries define a joint support and then use e.g. statistical transfers to allocate the renewable production among themselves.

Six EU countries have integrated the use of cooperation mechanisms into their NREAPs on a quantitative basis (ECN, 2011). In total, the expected cross-border trade accounts for the very limited amount of ca. 0.4% of the expected EU renewables production in 2020 (ECN, 2011).

Nevertheless, cooperation activities could become the next trend in the development of European renewable support. Several cooperation activities, especially in form of regional concepts have so far been announced. One example of ongoing cooperation is Italy, which imports RES-E from Serbia and therewith covers part of its renewable production target with that imported electricity. Norway and Sweden have jointly established a common certificate market and have implemented it in January 2012 (Ministry of Petroleum and Energy, 2010).

When cooperating on joint projects and joint support schemes, policy makers must coordinate their decisions and, in case of joint support schemes, also agree on a common policy type to be applied in the scheme, even if it is limited to certain technologies or areas. The need for agreement will in the nature of the case lead to further convergence of RES-E supports in Europe. The potential of cooperation options in relation to the effect on a convergence of national RES-E policy supports remains to be analysed. Assessing the related benefits, potential impacts and barriers

on the national and international levels will be key for contributing valuably to the discussion.

### **A.5.3 Future Trend 2 - Country independent renewable support**

Country-independent supplementary instruments are coming increasingly into focus. The more ‘traditional’ instruments such as investment grants and other non-repayable assistance are already broadly applied on European basis. Financial engineering instruments are a more recent phenomenon. Both are applied mostly independently from the national support system.

Most European initiatives are implemented through the European Investment Fund (EIF), which is part of the European Investment Bank (EIB). The following paragraph is based on information the EIF provides on its own website (EIF, 2012) and on de Jager et al. (2011, p.57-78). The EU-wide initiatives are typically designed for specific areas such as small and medium enterprises (SME) or urban development and are therewith not restricted to renewables support. The EIF/EIB provides practically all of the financial engineering instruments which are described in Section A.2. Their services range from venture capital investments (since 1997) to credit enhancement (since ca. 2007). The services are mostly financed through Programmes from the European Commission, for example within the Entrepreneurship and Innovation Programme reaching from 2007 to 2013, which includes a facility for equity investment (High growth and innovative SME Facility) and a facility for loan guarantees (SMEG). The most prominent examples for ‘novel’ EIF support are the JEREMIE and JESSICA programmes, financed as part of the European Structural Funds. Investors in renewable projects can be supported by equity and loan investments through revolving holding funds and by different guarantees.

The support provided by the EIF/EIB is country-independent in the sense that projects are supported independently from the national support scheme. It is not country-independent from a regulatory perspective, as each EU member state has to allow the EIB to act on its territory and/or has to allocate respective funds from the national budget, e.g. a share of the Structural Funds.

Financial engineering is a new area for renewable support and it is promoted by the European Union. In February 2011, the European Commission has published a Guidance Note on Financial Engineering Instruments (European Commission, 2011d) that supports the EU Member States in the implementation and the use of financial engineering instruments. Therefore it is most probable that the further developments of the national support schemes in this area will be orientated towards the European guidelines and will develop in a similar direction.

## A.6 Conclusions

This study has shown that there are indications for a bottom-up convergence of the choices of policy-makers regarding the types of policy to use and for which scope to implement them for supporting RES-E in the EU. National policy-makers are continuously implementing, changing and improving their support for RES-E in their country - and in that process, most national policy supports become increasingly similar. By undertaking an analysis of the type of RES-E supports implemented in each country of the EU for the years 2000 to 2011, several trends have been identified and discussed. The major developments observed are:

Firstly, all European countries have established at least one and on average even three support instruments for RES-E. The dominating support instruments are feed-in tariffs as major support scheme and investment grants as supplementary support scheme.

Secondly, the type of support becomes more tailored to the installation sizes. Smaller installations are significantly more often supported with feed-in tariff schemes than larger ones. The technology type is in this regard not a significant factor.

Thirdly, the policy instruments are used more in combinations with each other ('stacking' of policy instruments). Not only are major instruments combined with more supplementary instruments, also major support instruments are implemented in parallel. The dominant trend is combining FIT and FIP schemes. More recently, also TGC schemes are being combined with FIT. The trend of utilising multiple policy instruments at once could become an important development, as this increased flexibility of policy makers to apply multiple and differentiated policy instruments will be of advantage for further cross-border cooperation.

Potential driving factors for the observed trends have been discussed, such as the increased need for market integration and transitional processes. Two expected future trends have been introduced, namely the cooperation of countries on RES-E supports, possibly leading to first implementation of regional concepts in the near future, and the emergence of country-independent supports, especially in the area of financial engineering instruments.

Also outlier-countries have been discussed that diverge from the trends to apply price-control support (such as Sweden and Poland) and to 'stack' and differentiate instruments (such as Ireland and Germany). Certain approaches seem to be persistent in some countries. It remains to be seen if these countries will follow some of the common trends in the future or if the convergence will only be partial. However, the results of the analysis suggest that for a large majority of the European



countries, decisions on the types of policy to use and on the scope for which to implement them are slowly being more and more aligned even without direct policy intervention from European level. With that development continuing, an EU-driven ‘top-down’ harmonisation of support might become either dispensable or at least less controversial.

It is an interesting fact that at the same time as this bottom-up development is ongoing, the European Commission seems to have become more flexible in the discussion of national RES-E supports rather than a ‘top-down’ harmonisation, therewith opening up the room for a ‘best practice’ to evolve. One can expect that each of the two developments is influenced by the other.

There is certain reason to expect a further development into the direction of a bottom-up convergence of RES-E policy supports, amongst others because of new developments arising from cooperation mechanisms and new country-independent financing support in the European Union. Regional support concepts, where countries join up and establish common RES-E support schemes are expected to become a significant driving force towards more harmonised RES-E support in Europe.

## **Acknowledgement**

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# A.A Supplementary Information: Details on support scheme implementations in all EU Member States 2000-2011

APPENDIX. Supplementary material to: Kitzing et al. (2012), *Renewable energy policies in Europe: Converging or Diverging?*

EU Member State	First explicit RES-E support*	Major support instruments before 2000	Major support instruments in 2000					Major support instruments in 2005					Major support instruments in 2010					Major support instruments in 2011				
			Wind offsh.	Wind onsh.	Bio-mass	PV	Other	Wind offsh.	Wind onsh.	Bio-mass	PV	Other	Wind offsh.	Wind onsh.	Bio-mass	PV	Other	Wind offsh.	Wind onsh.	Bio-mass	PV	Other
1 Denmark	1979	1979-: INV, wind, biogas 1992-99: FIT, wind, biomass	FIT	FIT	FIT	FIT	FIT	TND(L) FIP	FIP	FIT	FIT	FIT	TND(L) FIP	FIP	FIT	FIT	FIT	TND(L) FIP	FIP	FIT	FIT	FIT
2 Portugal	1988	1988: FIT, all techn.	-	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	TND	TND	TND	TND	TND	FIT	FIT	FIT	FIT	FIT
3 Germany	1989	1989-96 (91-93): INV+FIT, wind (PV) from 1990: FIT, all techn.	-	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT
4 United Kingdom	1989/90	1990-88: TND, select. techn via the Non-fossil fuel obligation (NFFO)	-	transition phase				TGC	TGC	TGC	TGC	TGC	TGC Band	TGC Band	TGC Band	TGC Band	TGC Band	TGC Band	TGC Band	TGC Band	TGC Band	TGC Band
5 Italy	1992	1992-97: FIT, all techn.	-	-	INV	-	-	TGC	TGC	TGC	TGC	TGC	TGC Band	TGC Band	TGC Band	FIP	TGC Band	TGC Band	TGC Band	FIP	TGC Band	TGC Band
6 Belgium	1992	1992-: TAX, 1997-98: FIT	-	TAX				TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC
7 Austria	1992	1992-94: INV + FIT, PV	n/a	TGC				n/a	FIT	FIT	FIT	FIT	n/a	FIT	FIT	FIT	FIT	n/a	FIT	FIT	FIT	FIT
8 Sweden	1994	1994: TAX, all techn., 1994-2009: TAX, envir. bonus wind	-	TAX	TAX	TAX	TAX	-	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC
9 Greece	1994	1994-: InvGr, all techn.	-	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	-	FIT	FIT	TND(L) FIT(S)	FIT	-	FIT	FIT	TND(L) FIT(S)	FIT
10 Ireland	1994	1994-2003: TND, focus on wind	-	TND	TND	TAX	TAX	TAX	TAX	TAX	TAX	TAX	FIT	FIT	FIT	-	FIT	FIT	FIT	-	FIT	FIT
11 Luxembourg	1994	1994-: FIT	n/a	FIT	FIT(S)	FIT(S)	FIT(S)	n/a	FIT	FIT(S)	FIT(S)	FIT(S)	n/a	FIT	FIT(S)	FIT(S)	FIT(S)	n/a	FIT	FIT(S)	FIT(S)	FIT(S)
12 Netherlands	1994	1994-: TAX, 1995-: FIN (low interest loans)	-	TAX	TAX	TAX	TAX	FIT	FIT	FIT	FIT	FIT	TND(L)	FIT	FIT	FIT	FIT	TND(L)	FIT	FIT	FIT	FIT
13 France	1995	1995: INV, PV, hydro, wind 1996: TND wind	-	TND(L)	INV	INV	INV	-	TND	TND	TND	TND	-	FIT	TND(L)	TND(L)	TND(L)	TND(L)	FIT	TND(L)	TND(L)	TND(L)
14 Spain	1997	(from 1980 large hydropower) 1997-2004: FIT, all techn.	-	FIT	FIT	FIT	FIT	-	FIP	FIP	FIP	FIP	FIP	FIP	FIP	FIP	FIP	FIP	FIP	FIP	FIP	FIP
15 Finland	1997	1997-: TAX	TAX	TAX	TAX	-	-	TAX	TAX	TAX	TAX	TAX	TAX	TAX	TAX	TAX	TAX	FIT	FIT	FIT	-	FIT
16 Latvia	2002	2002-03: FIT, wind solar, biomass	-	transition phase				FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT
17 Lithuania	2002		-	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIP(S)	FIP	FIP(S)	FIP	FIP	FIP(S)	FIP	FIP(S)	FIP	FIP
18 Estonia	2003		-	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT
19 Hungary	2003		n/a	FIT	FIT	FIT	FIT	n/a	FIT	FIT	FIT	FIT	n/a	TND FIT(S)	FIT(S)	FIT	FIT	n/a	FIT(S)	FIT(S)	FIT	FIT
20 Malta	2004		-	INV(S)	-	FIT(S) INV(S)	-	-	INV(S)	-	FIT(S) INV(S)	-	-	INV(S)	-	FIT(S) INV(S)	-	-	INV(S)	-	FIT(S) INV(S)	-
21 Cyprus	2004		-	INV	INV	INV	INV	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT	FIT
22 Slovenia	2004		n/a	FIP	FIP	FIP	FIP	FIT(S)	FIT(S)	FIT(S)	FIT(S)	FIT(S)	n/a	FIP	FIP	FIP	FIP	n/a	FIP	FIP	FIP	FIP
23 Slovak Republic	2005		n/a	FIT	FIT	FIT	FIT	n/a	FIT	FIT	FIT	FIT	n/a	FIP	FIP(S)	FIP	FIP(S)	n/a	on hold	FIP(S)	on hold	FIP(S)
24 Romania	2005		n/a	TGC	TGC	TGC	TGC	n/a	TGC	TGC	TGC	TGC	n/a	TGC	TGC	TGC	TGC	n/a	TGC	TGC	TGC	TGC
25 Poland	2005		TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC	TGC
26 Czech Republic	2005/06		n/a	FIP	FIP	FIP	FIP	n/a	FIP	FIP	FIP	FIP	n/a	FIP	FIP	FIP	FIP	n/a	FIP	FIP	FIP	FIP
27 Bulgaria	2007		-	FIT	FIT	FIT	FIT	-	FIT	FIT	FIT	FIT	-	FIT	FIT	FIT	FIT	-	FIT	FIT(S)	FIT	FIT

Sources: BMU (2011), de Jager et al. (2011, p. 155ff), de Jager and Rathmann (2008), ECN (2011), European Commission (2011a), Haas et al. (2011), Held et al. (2010), Ragwitz et al. (2005, p. 35ff), Ragwitz et al. (2007), Ragwitz et al. (2011), Teckenburg et al. (2011)

FIT: Feed-in tariff, FIP: Feed-in Premium, FIT/P: Feed-in premium or feed-in tariff by choice, FIT(S): Feed-in tariff for small installations, typically <1MW, in some cases <5MW, in France <12MW; TGC: Tradable Green Certificates in a quota obligation system, TND: Tenders, TND(L): Tenders for large installations, >10MW, InvGr: Investment Grant (only mentioned if substantial amount of total cost and no other instrument available), TAX: Tax incentive or tax relief (only mentioned if applied as major support instrument); Other: include wave & tide, solar thermal, small scale hydro, geothermal, biogas

\* In order to appear in the statistics, a support scheme must be decided, implemented, in force, and open for new projects in the respective year. TGC systems must have a functional trading platform. Announced schemes, schemes with a legal basis but without implementation, and schemes without sufficient budget are not considered.

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PAPER B

# Risk implications of renewable support instruments: Comparative analysis of feed-in tariffs and premiums using a mean-variance approach

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**Abstract**

*Different support instruments for renewable energy expose investors differently to market risks. This has implications on the attractiveness of investment. We use mean-variance portfolio analysis to identify the risk implications of two support instruments: feed-in tariffs and feed-in premiums. Using cash flow analysis, Monte Carlo simulations and mean-variance analysis, we quantify risk-return relationships for an exemplary offshore wind park in a simplified setting. We show that feed-in tariffs systematically require lower direct support levels than feed-in premiums while providing the same attractiveness for investment, because they expose investors to less market risk. These risk implications should be considered when designing policy schemes.*

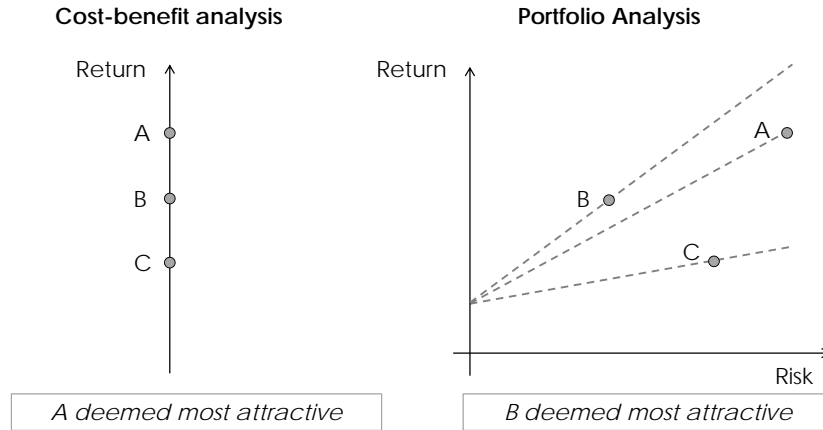
**Keywords:** Mean-variance analysis; Offshore wind; Energy policy; Feed-in tariffs

**B.1 Introduction**

To reach their targets for electricity production from renewable energy sources, many countries will have to accelerate deployment rates and increase investment in renewable energy projects. In Europe, annual investment in renewable energy has to approximately double to about EUR 70bn, so that the binding 2020 targets can be reached (de Jager et al., 2011). As the electricity sector in most European and American countries is liberalised, investments are generally profit-motivated and delivered by private investors reacting to respective financial incentives. A major role of governments with targets for renewable energy is thus to provide adequate incentives for such investments. For this, governments often use financial support instruments such as investment grants, tax breaks, feed-in tariffs and quota obligations with tradable certificate markets. The applied policy instruments shall be effective in achieving the targeted deployment at the lowest possible cost. To provide adequate financial incentives that balance between providing sufficient incentive for investment and avoiding high societal cost from support payments, it is essential that policy makers when designing policy schemes have similar considerations as private investors when preparing investment decisions.

Pure cost-benefit analyses, which are often the basis of policy decisions (Gross et al., 2010), are usually not sufficient for investors. One reason for this is that cost-benefit analyses only consider net benefit (or return) as key indicator for attractiveness of investment. This one-dimensional perspective can however lead to fatally wrong decisions as it does not inherently consider the risk of investment. This is illustrated in Figure B.1, where project A would be preferred in a cost-benefit analysis due to the highest return, although project B is in fact more attractive as it has the best risk-return relationship.

The recognition that expected return and the related risk are the only two - and equally important - indicators relevant for private investment decisions is a cornerstone of modern portfolio theory (Markowitz, 1952). The underlying approach is



**Figure B.1:** Diverging conclusions of cost-benefit analysis and portfolio analysis for the same hypothetical projects A, B and C (Kitzing and Ravn, 2013)

often referred to as mean-variance portfolio approach (MVP) (or mean-standard deviation approach) as risk and return are represented in the quantitative analysis by the two indicators mean (expected level of return) and variance (of the expected level of return). According to modern portfolio theory, a typical risk-averse investor would always require higher returns for riskier investments. For our analysis this is relevant as some support schemes inherently expose investors to more market risk than others. These support instruments would (all other things equal) consequently require higher direct support levels to compensate for the higher risk. It is from this basis that we start our analysis.

### B.1.1 Literature review

The MVP approach has been applied in the energy area to a considerable extent. It was first used to optimise fossil fuel procurement in the U.S. regulated electricity industry (Bar-Lev and Katz, 1976). The work of Awerbuch (1993) and Awerbuch (1995) started a new interest in the field, especially for analyses of optimal generation mixes on national and regional level, including the U.S. (Humphreys and McClain, 1998), the EU (Awerbuch and Berger, 2003), Italy (Arnesano et al., 2012), the Netherlands (Jansen et al., 2006), China (Zhu and Fan, 2010), and for combined heat and power in Germany (Westner and Madlener, 2011). MVP has also been applied for fuels and electricity in the worldwide transport sector (Guerrero-Lemus et al., 2012).

Awerbuch focused in his work mainly on risk on the cost side, i.e. fossil fuel cost. Arnesano et al. (2012) and Jansen et al. (2006) have additionally considered risk on the supply side such as risk from uncertain resource availability, which is especially relevant for renewable energies reliant on wind or solar irradiation. Roques et al. (2006) and Roques et al. (2008) have pioneered the application of MVP for analysis from the perspective of (private) investors in the electricity sector. They broadened



the scope of the analysis considering cost and revenue equally to analyse the full spectrum of incentives for investors.

In energy policy research, risk considerations play an increasing role (Mitchell et al. 2006, Wüstenhagen and Menichetti 2012). Different approaches are suggested, which are though mostly based on adding (more) risk elements into current cost-benefit approaches, e.g. by adjusting the discount rates or cost of capital (Gross et al. 2010, de Jager et al. 2008, Liebreich et al. 2011), by calculating a ‘risk-adjusted’ levelised cost (Levitt et al., 2011), and by using probability distributions in the net present value considerations (Falconett and Nagasaka, 2010). Approaches such as the MVP that handle risk inherently seem very suitable for the analysis of energy policy, and especially renewable support, as they give additional insights on the impact of uncertainties and risks for investors and society (as also briefly discussed in Wüstenhagen and Menichetti, 2012). Despite the interest in applying MVP in research on energy investments on the one hand, and the increasing interest in risk issues by energy policy research on the other hand, MVP has to the author’s knowledge not yet been applied for the analysis of energy policy instruments and required support levels. This paper bridges that gap.

### **B.1.2 Research interest**

The subject of investigation in this paper is to analyse the inherent relationship of risk and return for renewable energy under different support policies. A typical offshore wind project serves as case study, so that impacts on both the private investor (in form of attractiveness of investment) and society (in form of required support to be paid) can be quantitatively analysed in a concrete example. In principle, such analysis could be undertaken for any technology. Offshore wind investment is however a relevant topic in Europe as it has high deployment expectations but still relatively immature markets (Ragwitz et al., 2012). The decision on which support policy instrument to implement for offshore wind could be decisive for many countries in reaching their renewable energy targets.

In Europe, we see a recent trend to introduce Feed-in Premium (FIP) schemes for the support of renewable energy, either instead of or next to the previously more dominant Feed-in Tariff (FIT) schemes (seven EU countries have introduced FIP within the last decade, Kitzing et al. 2012). Combinations of FIT and FIP are implemented for example in Spain, where both schemes exist in parallel and producers can choose their preferred scheme (Schallenberg-Rodriguez and Haas, 2012).

We define FIT as schemes which provide guaranteed prices independent of the market price, where the support can be paid out either as ‘fixed FIT’ (the producer receives the guaranteed price in exchange for the produced power) or as ‘sliding premium FIT’ (the producer receives a sliding add-on to his sales on the market). The effect on income stability for investors is similar in both options. This definition of FIT is in line with Kitzing et al. (2012) and Couture and Gagnon (2010), but in contrast to

Klobasa et al. (2013), who describe the sliding premium FIT of Germany as a FIP. FIP schemes are in our analysis fixed add-ons to market prices. In many applications of FIT and FIP in Europe, the support levels are predetermined by law and are not escalated with inflation (Couture and Gagnon, 2010).

Because of the rising interest in FIP and the tendency of European countries to move from FIT to FIP schemes, we analyse risk implications of these two policy instruments, rather than focus on quota obligation schemes, which have been analysed to quite some extent in the past, e.g. in Neuhoﬀ and Butler (2008).

The focus of our analysis lies on the required direct support levels, which diverge because of the different risk exposures of investors. We do not consider indirect societal cost of renewable energies, such as integration or infrastructure cost. We acknowledge that such indirect effects can be substantial, as shown for integration issues in Lund (2005) and for infrastructure investment in Munoz et al. (2013) and Munoz et al. (2012). The risks associated with these costs should be considered in analyses that focus on the comprehensive evaluation of support schemes for society.

## B.2 Approach: Using mean-variance portfolio theory to investigate support policies

In decision making, the relationship between risk and return is essential. Investment decisions are based on expected average returns ( $\mu$ ), which is almost always subject to risk of deviation over time - This risk is expressed in the variance ( $\sigma^2$ ) or standard deviation ( $\sigma$ ) of the expected returns (Markowitz, 1952). The higher the standard deviation, the broader the spread of possible return outcomes and thus the higher the risk. The deviation is usually in both directions, so the resulting return can be higher or lower than expected. Risk analysis is thus always connected to the willingness and capability of the individual investor to tolerate volatility of an uncertain outcome, and not only about the probability of lower than expected outcomes. In line with modern portfolio theory and most financial analysis, we base our analysis on the assumption that all investors have some sort of risk aversion, meaning that the higher the outcome volatility an investor has to accept, the higher return he expects (Markowitz, 1952).

An investor can influence some sources of risk more than others (e.g. operations more than weather), either by avoiding risk (e.g. through stringent planning), mitigating risk (e.g. through good project management) or hedging and insuring against the risk. This has been studied extensively, e.g. in Pousinho et al. (2011) who discusses an optimised way for trading wind energy under uncertainty. Common insurance products for renewable energy projects are mostly targeting technology and project risk (UNEP SEFI, 2004). In the context of MVP, hedging is important. Portfolio theory states that any investor can diversify his portfolio in a way that he does not have to bear risk other than the risk of the general market development ('systematic

risk') (Brealey et al., 2008). Thus if an investor bears additional (unsystematic) risk, he does it voluntarily and should not be compensated for that. However, full diversification also requires that hedging is possible. For energy assets, it is not always likely that asset owners can find counter-parties with complementary risk attitudes. Roques et al. (2006) argue that electricity companies are likely to have to bear much of such cost of risk in their investment decisions.

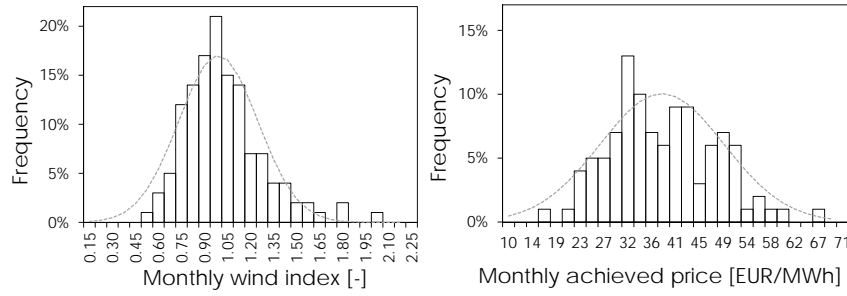
In our analysis, we consider market risk as represented by the power prices. Additionally, we consider wind resource availability as a major source of risk for wind energy investments. Because wind resource availability is never fully predictable in terms of volume and time, it is difficult even in the medium to short term to hedge against volume risk through future contracts and therewith to stabilise income. We acknowledge that recently, innovative products such as insurance against average wind resource availability have entered the market in some countries (Williams, 2011), but we consider them still as being the exception rather than the rule.

### **B.2.1 Application and applicability of the mean-variance approach**

The MVP approach has previously been criticised, see for example the discussion in Pézier (2011). Indeed, the applicability of MVP is subject to several restrictive conditions, such as that the returns must have a meaningful standard deviation. This means they have to be normally distributed or at least to have the same shape within a positive linear transformation (Pézier, 2011). This is by far not the case in all problems, and this condition can especially become an issue for complex structures such as an integrated energy system. Borch (1969) showed for example that in cases of stochastic domination, the MVP approach could lead to incorrect conclusions regarding the relative attractiveness of investments.

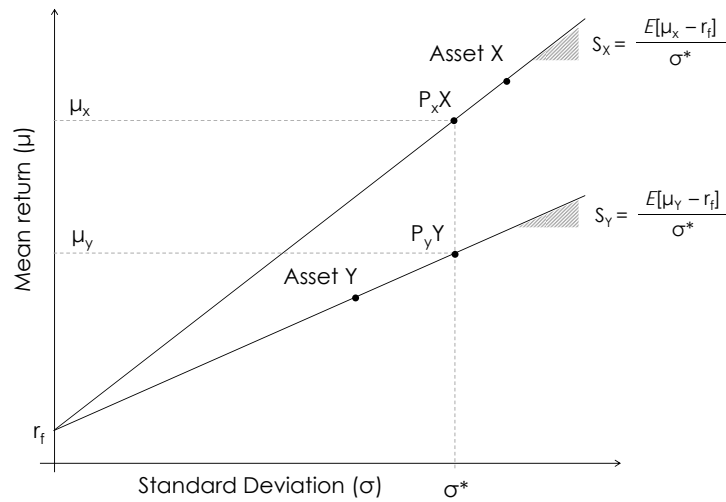
For our analysis, the stochastic variables (market prices and wind resource availability) considered should have characteristics of approximately normally distributed probability functions. This is a strong assumption of the approach. Our case data suggests that normal distributions are only acceptable as first approximation for the underlying data, as illustrated in Figure B.2. Different approximations for probability functions have been discussed for wind power a.o. in (Carta and Velázquez, 2011) and (Villanueva and Feijóo, 2010), who favour Weibull distributions over normal distributions. Regarding electricity price modelling, normal distributions are often used as approximation (see Dixit and Pindyck 1994 and Conejo et al. 2010), although prices can exhibit extreme short term spikes. For a monthly consideration as in our analysis, the effects of spikes are less significant. For example an extreme spike of up to 2000 EUR/MWh that occurred during four hours in June 2013 in West Denmark caused the monthly price to be 21% higher than the year average (Energinet.dk, 2013). Such a price of 47.9 EUR/MWh is well within the range of our scenario simulations.

With the assumption of normally distributed variables, our subject of investigation



**Figure B.2:** Distributions of wind energy production and achieved prices in the analysed case

stays within the boundaries as described by Sharpe: Our problem can be expressed as a case of ‘adding a zero-investment strategy to an existing risk-less portfolio’ (Sharpe, 1994). We base our case on an investor having a pre-existing portfolio that consists of a risk-less security, for which he considers adding an asset to increase the expected return ( $\mu$ ) while accepting a certain defined level of risk ( $\sigma^*$ ). When choosing between two (mutually exclusive) investments X and Y, which are both risky assets, any risk-averse investor would choose the one resulting in the more advantageous risk-return relationship, which in the example is the combination of the risk-less security and asset X at risk level ( $\sigma^*$ ), illustrated as  $P_X X$  in Figure B.3. Correlation is not relevant in this situation as the remaining holdings in the portfolio are risk-less (Sharpe, 1994).



**Figure B.3:** Attractiveness of mutually exclusive investments, based on Sharpe (1994)

The slope of the lines in Figure B.3 is the Sharpe Ratio  $S$  (Sharpe, 1994). It sets the expected excess return of an asset  $E[\mu - r_f]$  in relation to its standard deviation  $\sigma$ . Note that we use the excess return, i.e. the return above the risk-free rate  $r_f$ . The Sharpe Ratio thus measures how well an investor is compensated with return for a certain risk taken. In the example, the Sharpe Ratio of Asset X ( $S_X$ ) is higher than that of Asset Y ( $S_Y$ ). A higher Sharpe Ratio indicates a higher reward for assuming

risk - and this makes an investment opportunity more attractive. Asset X in the example is thus more attractive to an investor. The Sharpe Ratio is in effect a proxy for risk-adjusted return (Dowd, 2000).

In our analysis the mutually exclusive investments as described above are 1) the wind park under a FIT ('Asset X') and 2) the wind park under a FIP ('Asset Y'). We compare the Sharpe Ratios of these cases and then analyse the relative attractiveness of investment. From these results we determine the required support levels for each case. The resulting differences highlight one aspect of the comparative efficiency of the chosen support policy, namely the direct support payments. Other aspects (such as indirect cost) that would be important to evaluate policies in a comprehensive way cannot be covered by the mean-variance approach as applied in this analysis.

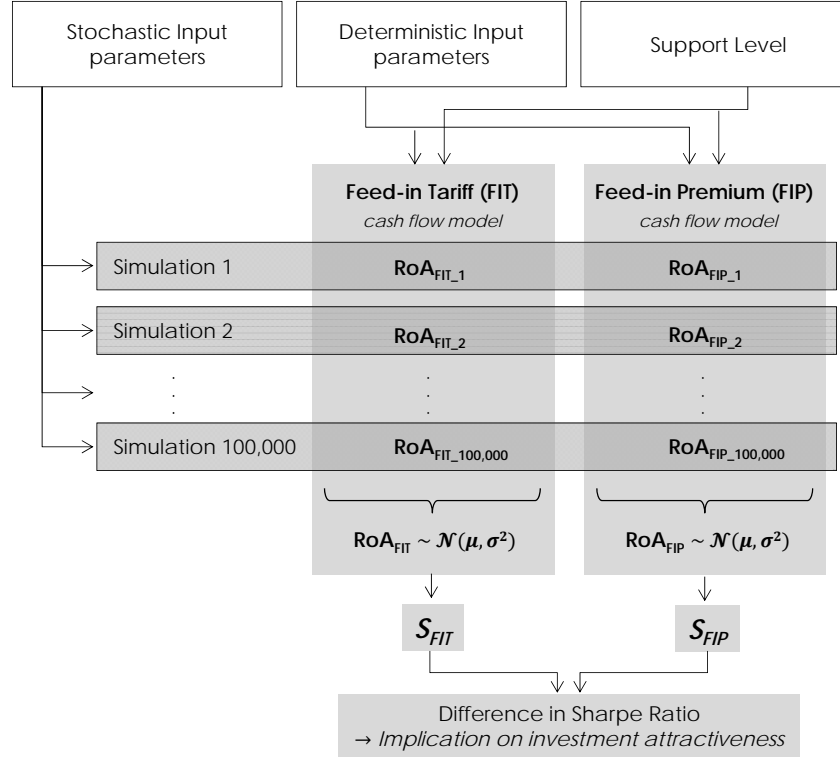
### **B.2.2 Return on asset as key parameter of the analysis**

For the further MVP analysis, we have to specify the term 'excess return'. In previous applications in the energy area, different approaches have been used: Awerbuch and Berger (2003) use the reciprocal of electricity generation cost (kWh/cent) as return. Roques et al. (2008), more focused on the investor's perspective, use net present value (NPV) normed per unit of capacity. We have chosen to use a single-year Return on Asset (RoA) indicator, for which the net cash flows of a single year are divided by the overall investment in the asset. Our specific aim of analysis, i.e. to show the main relationship between risk and return for different policy instruments and the relative implications on support levels, can easily be shown on basis of a single year. A full lifetime approach including the investigation of effects from structural market changes is not in the scope of this paper. Further related research options are though discussed in Section B.5.

### **B.2.3 Calculation method**

We have created a cash flow model for an exemplary offshore wind park in West Denmark. The cash flow analysis, created in Microsoft Excel (2010), uses Monte Carlo simulations to generate stochastic inputs, which are undertaken in the Oracle Crystal Ball (2013) extension. The resulting expected average returns and variances are the inputs for the subsequent mean-variance analysis using the Sharpe Ratio. For each set of simulations, we calculate the cash flows for the FIT and FIP schemes in parallel, meaning they use exactly the same random input variables in each simulation step, in order to avoid coincidental divergence of the results. The procedure for one set of simulations is illustrated in Figure B.4.

We let the model perform several different sets of Monte Carlo simulations, one for each possible support level. We then undertake additional sets of simulations for the sensitivity analysis, by variation of deterministic inputs (price level, production



**Figure B.4:** Procedure for one set of simulations (repeated for each support level)

volume, investment and operational cost) as well as stochastic inputs (volatility of prices and production volumes).

### B.3 Data and assumptions

The cash flows considered in this analysis comprise of a revenue part, which is income from sales on the market (spot power price) and income from the financial support scheme (FIT or FIP), and of a cost part, which is investment cost, Operation and Maintenance (O&M) cost as well as a balancing cost element. All elements except investment cost are in our (simplified) analysis dependent on the amount of electricity generated and thus on the available wind resource. Investment cost are considered sunk and thus fixed cost.

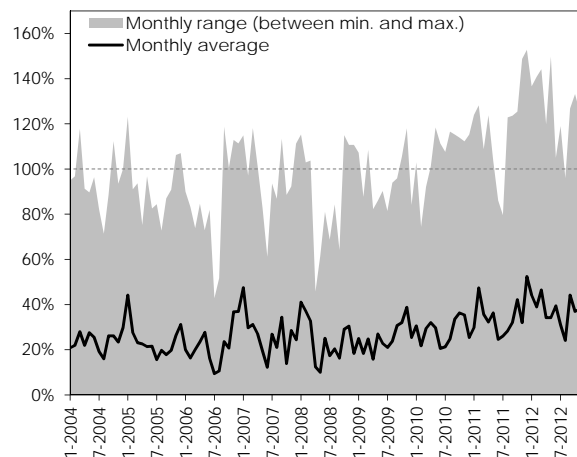
The time resolution is chosen as is most reasonable for the analysis. An analysis with yearly inputs only would be too simplistic because of seasonal variations of mean levels and volatilities especially for wind energy production volume. In order to capture short term stochasticity on a weekly, daily or even hourly basis, an approach different from a mean-variance analysis would have been appropriate. In the short term, production and market prices follow a path and could not have been modelled as independent normally distributed variables. In this case, a model based

on e.g. random walks or Brownian motions would have been required, for example as undertaken in Kitzing and Schröder (2012). Such analysis can however not directly serve as basis for the MVP approach, so for the purpose of our analysis, we confine to a monthly basis for stochastic variations. At the same time, in order to correctly analyse the market revenues, we still need to consider hourly prices and production levels. For this, we use the indicator of ‘market value’ of wind, as described below.

The input parameters and assumptions were determined by a review of several sources using different units. For our purpose, all monetary values are converted to 2012 levels and Euro using inflation and exchange rate data from Statistics Denmark (2013). Unless otherwise specified, all monetary values are shown in terms of 2012 Euros.

### B.3.1 Why an offshore wind park in West Denmark?

West Denmark is a showcase for offshore wind. By the end of 2013, West Denmark will have 810 MW of offshore wind power installed - in addition to 2.88 GW of onshore wind (Energinet.dk, 2012). This corresponds roughly to the normal maximum power consumption in the area, which is 3.7 GW. In recent years a considerable share of overall electricity demand has already been covered by wind energy, namely 34.9% (in 2011) and 38.1% (in 2012). Figure B.5 shows the monthly average share of wind production as well as the range of minimum and maximum monthly production for the past nine years. Electricity generation from wind energy alone exceeded overall demand for a significant amount of time, namely during 226 hours (2011) and 342 hours (2012) (all based on data from Energinet.dk 2013).

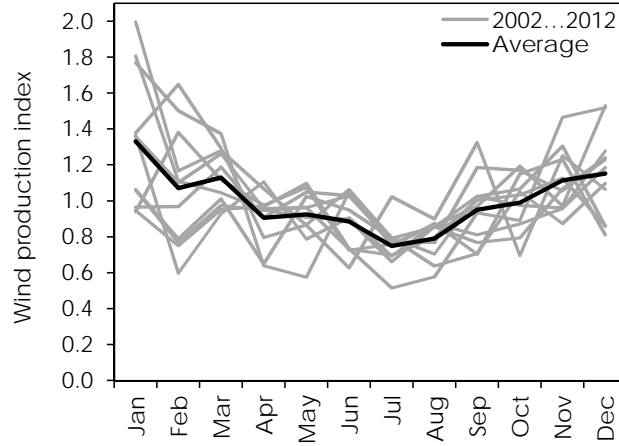


**Figure B.5:** Electricity production from wind as share of gross demand in West Denmark, based on data from Energinet.dk (2013)

### B.3.2 Wind production volume and market prices

As average yearly wind production, we use 4003 MWh/MW for a normal wind year, which is an expected average for an offshore wind park installed in 2015 (Danish Energy Agency, 2012b). From historical production data 2004-2008, we can see that North Sea installations have achieved 4182 MWh/MW, which is approx. 4% higher, whereas inner seas installations in Denmark have achieved 3888 MWh/MW, approx. 3% lower (Danish Energy Agency, 2012b). The expected production volume is at an assumed full availability, so we (following the approach of Danish Energy Agency 2012b) only apply 96% of the gross production, i.e. 3843 MWh/MW per year or 320 MWh/MW per month, to account for non-availability due to breakdowns and planned maintenance periods.

We use a monthly index  $I_{i,j}$  of offshore wind production based on the data provided by EMD (2013). We use this index rather than hourly production data directly, because EMD have, based on detailed hourly offshore production data, already matched production to the respective installed capacities in the area. The offshore wind production index for West Denmark exhibits a clear seasonal trend: Production tends to be higher in winter months with an equally higher variance, as illustrated in Figure B.6.



**Figure B.6:** Offshore wind production index, normalised to an average wind year in West Denmark, based on data from EMD (2013)

We derive the average monthly wind energy production  $\bar{P}_j$  for the months  $j = 1 \dots 12$  as simple average over the sample years  $i = 1 \dots m$ :

$$\bar{P}_j \left[ \frac{MWh}{MW} \right] = \frac{1}{m} * \sum_{i=1}^m \left( \beta * I_{i,j} * 320 \left[ \frac{MWh}{MW} \right] \right) \quad (B.1)$$

where  $I_{i,j}$  is the monthly index from EMD (2013). 320 MWh/MW is the monthly wind production of a normal year. The indices are multiplied by  $\beta = \frac{1}{0.95}$ , because



the data basis of the years 2002-2012 exhibits an average index of only 0.95, which means that the data represent a period which was 5% worse than normal. To make the monthly indices fit with the production of a normal year, they are thus normalised by constant  $\beta$ . This has no influence on the volatility calculation. The related volatility  $\sigma_{\bar{P}_j}$  is based on the standard deviation of the monthly index applied to the respective average monthly production:

$$\sigma_{\bar{P}_j} = \frac{1}{\bar{I}_j} * \left( \frac{\sum_{i=1}^m (I_{i,j} - \bar{I}_j)^2}{(m-1)} \right)^{\frac{1}{2}} * \bar{P}_j \quad (\text{B.2})$$

Table B.1 summarises the wind production inputs used in the cash flow model.

**Table B.1:** Stochastic Input parameters for the analysis, average of years 2002-2012 (volumes) and 2004-2012 (prices)

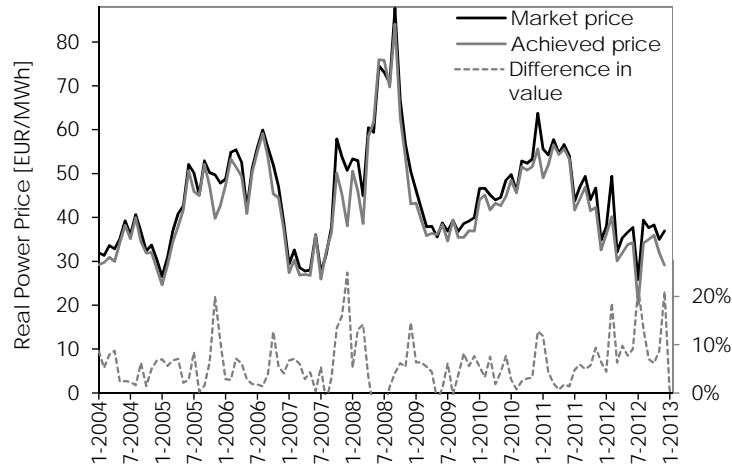
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
<b>Production volume</b> [MWh/MW]	Mean ( $\mu$ )	426	343	362	290	296	284	240	253	304	317	357	369	<b>3,843</b>
	St.Dev. ( $\sigma$ )	122	108	50	49	48	50	39	34	63	52	58	79	<b>63</b>
	Coeff. of Variation ( $\sigma/\mu$ )	29%	31%	14%	17%	16%	18%	16%	14%	21%	16%	16%	21%	<b>19%</b>
<b>Market value of wind/achiev. price</b> [EUR/MWh]	Mean ( $\mu$ )	37.1	38.7	36.6	38.4	39.1	44.1	39.1	42.9	44.5	42.6	40.2	36.7	<b>40.0</b>
	St.Dev. ( $\sigma$ )	6.7	6.6	6.2	3.6	4.6	4.2	8.0	4.3	5.6	7.4	5.7	7.2	<b>5.8</b>
	Coeff. of Variation ( $\sigma/\mu$ )	18%	17%	17%	9%	12%	10%	20%	10%	13%	17%	14%	20%	<b>15%</b>

As proxy for market prices, we use day-ahead spot prices for West Denmark as formed on Nord Pool (the common electricity market of the Nordic countries, Nord Pool 2013). The Danish electricity system is divided into two different synchronous zones (West and East Denmark), which are only connected by one interconnector. This division is also reflected in the Nord Pool Spot price zones. The prices in West Denmark tend to be somewhat lower than in East Denmark (Nordic Energy Regulators, 2012) and are more influenced by the Central European market. We assume the use of financial future contracts (traded up to six years ahead) to be limited due to the uncertain wind resource availability. Concerning intraday trading (on Elbas), we assume that wind parks participate there to mitigate balancing cost only. Balancing cost are included in the analysis as deterministic cost element only (see Section B.3.5).

In order to capture the correct revenues from the market for the wind park, we have to include hourly considerations, as both the prices and the production volume vary on a short-term basis. We do this by using the concept of ‘market value’ of wind, see also Sensfuss et al. (2007) and Hirth (2013). In this approach, historic data on hourly market prices and wind production is used to determine the average monthly price achieved by wind power production as compared to the average market price. We can then base our monthly simulation on the expected achieved prices of wind as opposed to the expected overall market prices. As long as there is no structural

change in the price formation on the market, this indicator is a good proxy for the market revenue of wind.

The required hourly data is available for West Denmark for the years 2004-2012 from Energinet.dk (2013). In Figure B.7, the market prices, the related achieved prices and the differences between the two are illustrated.

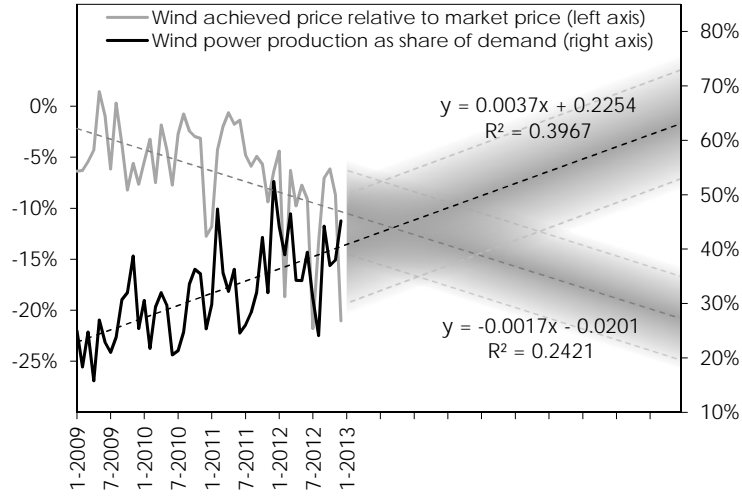


**Figure B.7:** Monthly average market prices and wind achieved prices, 2004-2012 in West Denmark, based on data from Energinet.dk (2013)

In general, the two prices are closely correlated. The prices achieved by wind are though systematically lower than the market average. For example in the years 2009-2012, the market value of wind was on average 6.3% lower than the average market price, varying between +1.4% and -21.8% on a monthly basis. This systematically lower value of wind can be due to different reasons. First of all, the wind patterns could be coincidentally so that more wind energy is produced during times in which market prices are low (off-peak periods). Another effect is experienced especially in markets with very high share of wind energy production where the wind production with its very low marginal cost is impacting the price formation on the spot market, pushing higher cost technologies out of the market. This effect is also referred to as 'merit order effect' (see Sensfuss et al. 2007), and has been shown to exist on the Danish market as early as for the year 2005 (Munksgaard and Morthorst, 2008).

Trends from recent years with significant growth of offshore wind production in West Denmark (2009-2012) also support the assessment that the merit order effect may be correlated to the market share of wind energy (see Figure B.8).

A further increase of wind production is expected in Denmark (up to an average market share of 50% already in 2020, according to the official Danish energy policy plan, Danish Energy Agency 2012a). With the approach taken in our analysis, we can simulate a possible future intensifying of this effect simply by lowering the input parameter 'wind achieved power price'. This is done in the sensitivity analysis.



**Figure B.8:** Market value of wind and share of wind, historical data and trends for West Denmark, based on data from Energinet.dk (2013)

We derive the average achieved price  $\bar{\varphi}_j$  [EUR/MWh] for each month  $j = 1 \dots 12$  as the average over the sample years  $i = 1 \dots m$  of the weighted arithmetic means of the monthly revenues over the production:

$$\bar{\varphi}_j = \frac{1}{m} * \sum_{i=1}^m \left( \frac{\sum_{h=1}^n (P_{h,i,j} * p_{h,i,j})}{\sum_{h=1}^n (P_{h,i,j})} \right) \quad (\text{B.3})$$

with  $h$  representing the hours of the month (e.g. in January from 1 to 744).  $P_{h,i,j}$  [MWh] is the hourly production volume for the respective month and year, and  $p_{h,i,j}$  [EUR/MWh] is the hourly spot price.

As shown in Equation (B.3), we use for each month an achieved price derived from the average real prices of historical years. The related volatility is the direct and simple standard deviation  $\sigma_{\bar{\varphi}_j}$ . We assume that market prices are not significantly altered when introducing a FIP. In our analysis, overall renewable production volumes remain the same in the comparative calculation, so market prices would only be affected in situations in which the sliding-premium FIT and the fixed FIP give different incentives to the sellers, i.e. extreme negative prices. Market price effects are thus expected to be limited. This simplification should nevertheless be kept in mind when interpreting the results. Table B.1 summarises the price inputs used in the cash flow model.

### B.3.3 Support schemes

For the modelling of support schemes, we use schemes similar to the ones applying to operating wind parks in Denmark. All large Danish offshore wind parks are currently supported by a tendered target-price feed-in tariff (as defined in Kitizing et al., 2012). This means that the FIT is paid out as a sliding premium between the guaranteed price and the market price. The different levels are illustrated in Table B.2.

**Table B.2:** Feed-in tariffs for three Danish offshore wind parks, converted to Euro from Danish Energy Agency (2009a)

	Tender	Guaranteed Price [EUR/MWh]	Support level [EUR/MWh] at market price of 40 EUR/MWh
Horns Rev 2	2004	69.53	29.53
Rødsand 2	2007	84.43	44.43
Anholt	2009	141.07	101.07

The FITs apply to 10 TWh (for Horns Rev 2 and Rødsand 2) and 20 TWh (for Anholt) of production, corresponding to approx. 12-15 years of operation and are constant in nominal terms (Danish Energy Agency, 2009b). The price guarantee is implemented in form of a sliding premium, i.e. a variable add-on on top of the market price. The add-on is determined on hourly basis as difference of the guaranteed price and the spot price in the respective Nord Pool price zone. When spot prices are below zero, no support is paid out (Danish Energy Agency, 2009a).

For the alternative policy scenario we use a FIP similar to the scheme currently applicable to onshore wind in Denmark, which is a fixed premium of approximately 34 EUR/MWh paid out as add-on to the market price, also constant in nominal terms (Danish Energy Agency, 2009b).

A wind park operating under the FIT scheme is only exposed to one major revenue risk, namely uncertainty about production volume, i.e. the amount of electricity that can be sold at the guaranteed price. Under the FIP scheme, his revenues are subject to market price risk as well as to risk in production volume.

In our analysis, we test the risk implications of the two described support schemes for support levels between 0 EUR/MWh and 80 EUR/MWh, which is well above what is expected as support level for future wind parks in Denmark under a similar support scheme as the existing one (Deloitte, 2011). For FIPs, the support level corresponds directly to the guaranteed add-on. For FITs, the support level is calculated as the guaranteed price minus the market value of wind. For example a support level of 40 EUR/MWh corresponds to a FIP of 40 EUR/MWh on top of the market price (e.g. 50 EUR/MWh) and to a guaranteed price under the FIT of 90 EUR/MWh (including both the level of support and the market price). The same support level thus results for both schemes (FIT and FIP) in the same average income for the wind park and thus the same average RoA. The same support level also results in the same direct support payment burden to society.

### B.3.4 Technology data

Estimates of technology cost differ significantly in publications about offshore wind parks. A description of current technological and economic developments in offshore wind technology can be found in Sun et al. (2012). Table B.3 gives an overview of average figures as well as ranges of investment cost and O&M cost of some relevant studies. We apply mid range values for our base case and make sensitivities for all maximum and minimum values.

**Table B.3:** Investment and Operation and Maintenance cost for offshore wind, all prices converted to real 2012

	Reference year and source	Investment [mEUR/ MW]		O&M [EUR/ MWh]	
		Average	Min - Max	Average	Min - Max
<b>Empirical data</b>	2002-2009 (operating parks), Danish Energy Agency (2012b)	2.2	1.4 - 2.8		
	2006, Morthorst et al. (2009)	2.4	2.1 - 2.8	18	
	2010 (German projects), KPMG (2010)	3.7	3.4 - 4.0	27	
	2010-2013 (planned parks), Danish Energy Agency (2012b)	3.2	2.4 - 3.9		
<b>Forecast</b>	2015, Morthorst et al. (2009)	2.1	1.8 - 2.4	15	
	2015, Danish Energy Agency (2012b)	3.2		19	
	2020 (market balance), Danish Energy Agency (2012b)	2.5		17	
	<b>Applied in this analysis</b>	2.6	1.8 - 3.9	18	15 - 27

### B.3.5 Other assumptions

As additional cost element, we apply a deduction of 5% on the achieved price to account for balancing expenses arising from wind forecast errors and trading. This deduction lies in the middle of the range of balancing cost identified for West Denmark by Holttinen et al. (2011).

As approximation for the risk-free rate, we use the analysis by Credit Suisse (2013), who have found that the average risk-free rate (approximated from the average interest rate of short-term government bills issued) between 1963-2012 was 2.7% in real terms. We choose such a long time horizon, so that our results are less influenced by short term developments such as the recent economic crisis. Equity risk premium in Denmark was 3.5% during the same time period (Credit Suisse, 2013). The overall real market interest rate can thus be approximated to 6.2%. We use this as benchmark in the further analysis.

### B.3.6 Scope and limitations

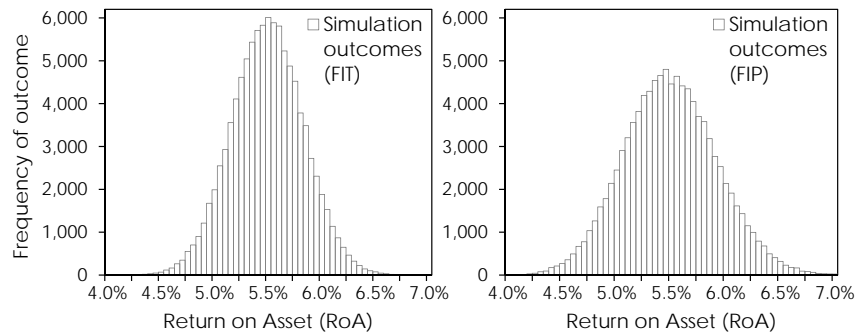
Our analysis has some significant simplifications and estimations. We assume normal distributions for monthly wind power production and achieved market prices. We do not use a specific offshore wind park, but base our cost assumptions on average values only. This serves our purpose of showing a general relationship between risk-return and required support levels.

We do not consider inflation, which to our evaluation is not a significant issue because the analysis is based on a single year only. Inflation and especially inflation risk could be an interesting subject of investigation for future more long-term analyses.

Our study is based on a pre-tax analysis, so the resulting RoA should not be compared to usual after-tax company hurdle-rates. In general, taxes can be a significant element for consideration in investment decisions. Future studies going beyond showing the principle risk-return relations of different support schemes, should take this into consideration.

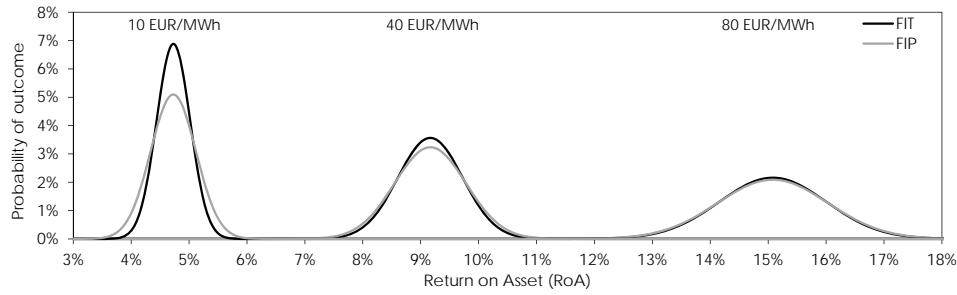
## B.4 Results

The results from the cash flow analysis show that for each level of support, the FIT and the FIP schemes result in the same expected mean RoA. At the same time, the FIT exhibits a lower variance of RoA than the FIP. Results of an exemplary set of simulations are shown in Figure B.9.



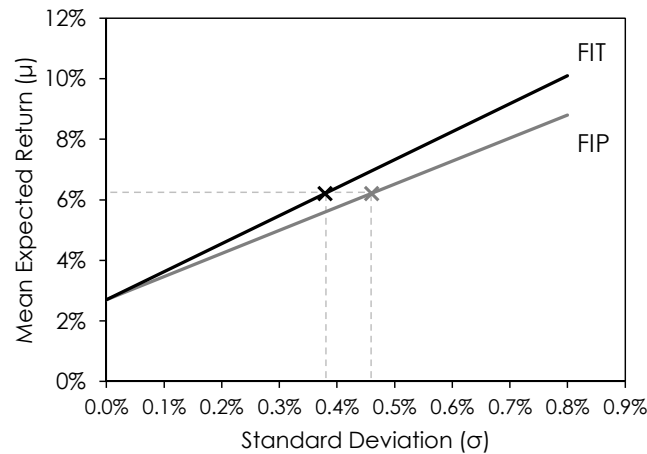
**Figure B.9:** RoA distributions for an exemplary set of 100,000 simulations (support level 15 EUR/MWh)

Figure B.10 illustrates the resulting normal distributions for three different support levels. It becomes apparent that the differences between FIT and FIP are more significant for lower support levels than for higher levels.



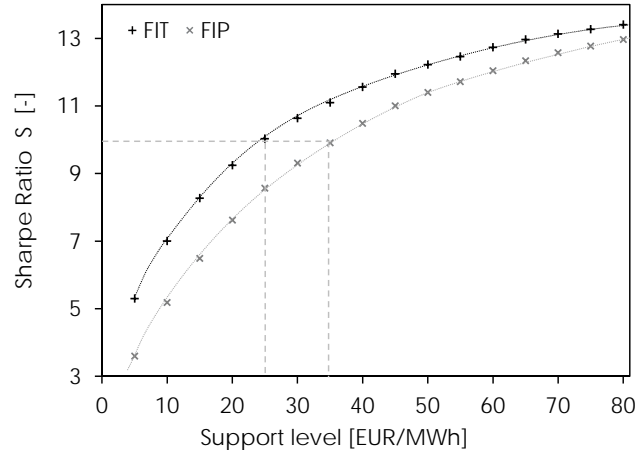
**Figure B.10:** Resulting normal distributions of RoA for support levels of 10 EUR/MWh, 40 EUR/MWh and 80 EUR/MWh

Using the results of the cash flow analysis, we conduct the mean-variance analysis. Figure B.11 shows the relation of mean expected return and risk for the two different support schemes at an exemplary mid-range support level. Here, the FIP scheme exposes the investor for the same mean expected RoA to more risk (the RoA has a higher variance), and its Sharpe Ratio is lower (which can be seen in the lower gradient of the line). The FIP is thus less attractive for an investor.



**Figure B.11:** Results of the simulations for the same mean, here with a support level of 20 EUR/MWh

A government wishing to uphold the same attractiveness of investment under both policy support schemes (i.e. to keep the Sharpe Ratio constant) would have to provide a considerably higher support level under a FIP scheme than under a FIT scheme. The difference in required support level can be read from Figure B.12. In the example indicated with dashed lines, the FIP scheme would require a market add-on of 35 EUR/MWh, which is 40% higher than the required support level under a FIT scheme (25 EUR/MWh).



**Figure B.12:** Required support level dependent on the Sharpe Ratio, for the two support policy schemes FIT and FIP

The resulting Sharpe Ratios presented here may seem very high when compared to rates normally dealt with in financial analysis, where ratios of three usually already are deemed as very good investments. The reason for such high ratios lies mainly in the time frames we have chosen for the analysis. Usually, financial analyses would be based on more frequent and short term changes. For example market traded investments (such as stocks) may change their price many times each day, often with high volatility. Modelling the monthly volatility of electricity prices and wind volumes only, we have a different basis. Additionally, we investigate assets under a strong support scheme that reduces risk exposure of the investor significantly as compared to other (not supported) assets.

#### B.4.1 Sensitivity Analysis

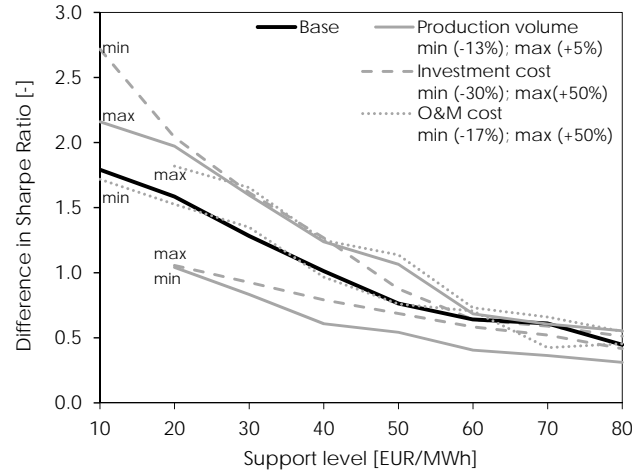
We undertake sensitivity analysis on the most significant deterministic and stochastic inputs. The sensitivities are undertaken *ceteris paribus* towards the base case and are based on 10,000 runs per set of Monte Carlo simulation only to save time and data handling. The effects of this simplification have been tested and are minor.

The results of the sensitivity analyses are presented in graphs showing the difference in Sharpe Ratio between FIT and FIP schemes ( $S_{FIT} - S_{FIP}$ ) at all investigated support levels. A positive difference indicates that the FIT is more attractive at a given support level. Results with a RoA lower than the risk-free rate (and therefore negative Sharpe Ratio) are not shown.

All sensitivities are constructed based on a range of variations derived from historical data. For example the production volume is tested for a 13% decrease as compared to base case, corresponding to the lowest annual production of offshore wind in Denmark during the investigated period (in the year 2010), and a 5% increase, corresponding to



the highest level of offshore wind production yet seen (in the year 2007). Investment and O&M costs are varied with the ranges as shown in Table B.3. The results of the sensitivity analyses on deterministic input parameters are shown in Figure B.13.

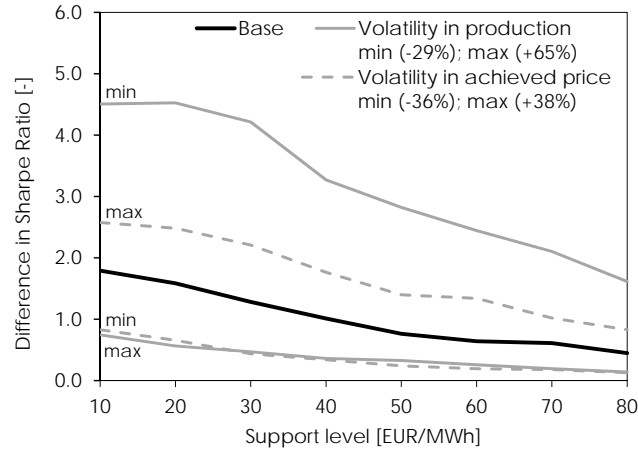


**Figure B.13:** Sensitivities on deterministic input parameters production volume, investment and O&M cost

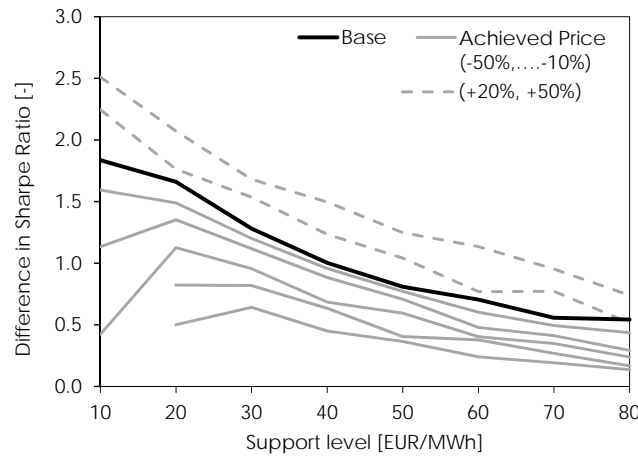
Regarding the stochastic input parameters, we have tested the volatility of production volume and of achieved prices for the most extreme months in our data set. This means that we have created fictive situations in which all months of the year exhibit a similar variation than in the month with the lowest and the highest coefficient of variation, respectively (which are shown in Table B.1). The results are shown in Figure B.14. The higher the volatility in production volume, the lower the difference between the FIT and FIP scheme. This is because the FIT scheme reduces only risk on the price side and not the volume side. The higher the impact of the volume risk as compared to price risk, the lower the benefit. In contrast, with increasing volatility of prices, the FIT becomes ever more advantageous over the FIP.

The sensitivity analysis for level of achieved prices as shown in Figure B.15 is undertaken separately in order to account for the expected increase of merit order effect as described in Section B.3.2. We have tested for changes down to  $-50\%$  (corresponding to an average achieved price of 20 EUR/MWh). For reference, we have also tested increases of the prices up to 80 EUR/MWh. The range of the sensitivities is well above what has previously been seen on the market, where the highest historical annual average price was in 2008 at 60.0 EUR/MWh and the lowest in 2012 at 32.7 EUR/MWh.

The results are rather sensitive to the assumed risk-free rate, because of the way the Sharpe Ratio is constructed. Sharpe himself discusses this in detail with a demonstrative example in Sharpe (1994). Figure B.16 shows the sensitivity of results to a variation of the risk-free rate. The lowest risk-free rates result in the largest differences. The impact is largest for very low support levels. This is because at these low levels, the risk-free rate dominates over the RoA (in the base case this is



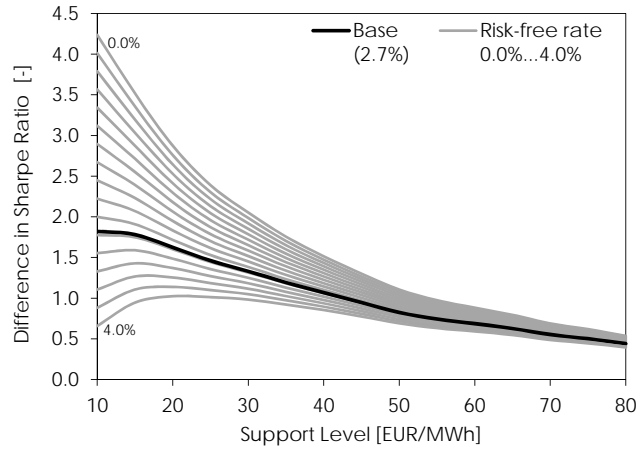
**Figure B.14:** Sensitivities on stochastic input parameters volatility in production volume and volatility in achieved prices



**Figure B.15:** Sensitivities on achieved price, variation between -50% and +50%

2.7% as compared to 3.99% for a support level of 10 EUR/MWh) when determining the excess return (in the example only 1.27%), which is then divided by the standard deviation to arrive at the Sharpe Ratio. This effect reduces naturally with increasing support levels.

We can conclude that two major characteristics of our results remain robust in all investigated cases. Firstly, the difference in Sharpe Ratios ( $S_{FIT} - S_{FIP}$ ) is positive in all cases at all support levels, which indicates that for any given support level the FIT scheme is always more attractive for an investor. Secondly, we see a decreasing difference with increasing support levels, which implies that choice of policy instrument is especially relevant for low support levels.



**Figure B.16:** Sensitivities on risk-free rate

## B.5 Discussion

The findings as presented above can help to improve policy design in terms of effectiveness and cost-efficiency. On the one hand, they give an indication of what policy makers could consider to better accommodate the needs of investors: If a policy scheme exposes investors to market risk, this should be acknowledged and investors should be compensated adequately for the risk taken. On the other hand, the findings can be used to avoiding windfall profits of certain policy schemes: If a policy scheme reduces risk for investors to a considerable amount, then investment can be attractive at relatively low support levels.

The simulations show that for the base case as well as for the sensitivities, the largest difference in Sharpe Ratio is for low support levels. This means that with technology progress and thus lower required support levels, it becomes more and more relevant to consider the risk implications of support schemes.

The results of this analysis are very much in line with the findings of Schallenberg-Rodriguez and Haas (2012), who showed empirically for Spain that wind energy investors required a 10-20 EUR/MWh incentive to move from the FIT to the FIP scheme. Our results are though seemingly in contrast to a recent analysis on the Nordic market by Kopsakangas-Savolainen and Svento (2013), who conclude that FIT would be more expensive for society. The major difference to our analysis is that Kopsakangas-Savolainen and Svento (2013) compare a predetermined FIT, which allows significant windfall profits for investors through inefficiently set support levels, with an ‘economically sound’ FIP. In our analysis, we calculate the required support levels at which the investors’ return expectations are exactly satisfied, and therewith determine the ‘economically sound’ level for both the FIT and the FIP. Windfall profits would thus only occur, if the support is set at a level deviating from the one resulting from our analysis. The results can therefore not be directly compared.

In order to use the method as presented in this paper for concrete policy considerations under real market conditions, a systemic approach must be taken capturing structural market effects over time. This would require using an optimisation dispatch model that can forecast production and power prices for a complete energy system, and thus e.g. inherently incorporate the changes in the merit order effect of wind. Such research is already ongoing and preliminary results are published in Kitzing and Ravn (2013).

An issue that has not been analysed here is which policy instrument in general would be more favourable for society. For such an analysis, not only direct support payments, but also indirect effects (such as integration and infrastructure costs and their risks) need to be investigated. The results presented here show merely that risk implications should be considered when designing policies, otherwise significant unintended changes in investment incentive could occur, possibly leading to either unfulfilled deployment targets or windfall profits.

## **B.6 Conclusions**

We have used a mean-variance approach to show that the choice of policy instrument for the support of renewable energy can have a decisive impact on the required support level and thus the effectiveness and cost-efficiency of the scheme. Choosing a policy instrument that exposes investors to more market risk requires higher support levels when the investment incentive shall be upheld.

Through cash flow analysis, Monte Carlo simulations and subsequent comparison of Sharpe Ratios for an exemplary offshore wind park in West Denmark, we have shown that feed-in tariffs generally require lower support levels than feed-in premiums while providing the same attractiveness for investment regarding the risk-return relationship. This is because risk-averse investors can accept lower returns when revenues are more stable. The difference in required support payments is in our case up to 10 EUR/MWh (or up to 40%). The sensitivity analyses undertaken for all major input parameters confirm the robustness of the results.

The focus of this paper was to principally show how the choice of policy instrument can impact the risk-return relationship of investments and what the implications for investment attractiveness and required support payments can be. The next step would be to use this insight for further investigations which include the analysis of effects from long-term market developments (including the merit order effect) and more specific investment opportunities. For now, we have shown that risk implications cannot be neglected in the design of policy schemes.

## Acknowledgements

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PAPER C

# Support mechanisms and risk: Implications on the Nordic electricity system

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**Abstract**

*Investments in renewable energy projects, such as offshore wind parks, are very much dependent on financial support. The type of policy instrument chosen for such support determines investors' exposure to market risk, and thus influences which rate of return they expect to achieve. We make a stochastic analysis for the Nordic electricity system by conducting simulations with the energy system model Balmorel and by applying the mean-standard deviation approach of modern portfolio theory to quantify risk implications of policy instruments for an exemplary offshore wind park. The analysis reveals that the two support policy schemes Feed-in Tariffs and Feed-in Premiums provide different risk-return relationships. In the investigated case, a Feed-in Premium scheme would require a 13% higher support level, because of a 6% higher exposure of investors to market risk. Our findings can help when designing policy support, both regarding type of policy chosen and level of support.*

**Keywords:** Power system modelling; Risk analysis; Stochastic processes; Wind energy; Finance

**C.1 Introduction**

Today, policy makers in Europe apply a broad variety of energy policy instruments and many of them aim at attracting investment in renewable energy projects. For an effective and efficient design of support policies for renewable energies, it is crucial that policy makers understand the considerations and assessments that private investors have in preparation of investment decisions. Modern portfolio theory shows that private investment decisions are not based on pure cost-benefit-analyses, but rather on the relationship between expected return and risk. A typical risk-averse investor would require higher levels of return for riskier investments. Some support policy instruments expose investors to higher market risk than others. These support instruments would consequently require a higher support level in order to compensate the higher risk with a higher return.

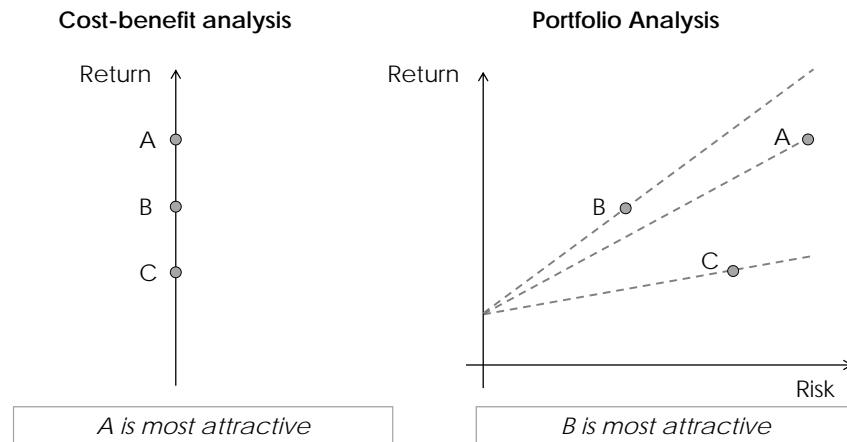
The subject of this analysis is to investigate and quantify the relationship of risk and return under different support policy instruments for an exemplary offshore wind park investment in the Nordic electricity system. For the quantitative risk assessment, the existing energy systems model Balmorel is expanded to permit stochastic simulation with exogenously given energy technology capacities. Using the system model for the four Nordic countries, Monte Carlo simulations are performed, in which fuel prices, wind power resources and hydro reservoir levels are considered as stochastic variables. The resulting expected values and probability distributions of power prices, producers' cash flows and support payments are used to analyse the attractiveness of investments, the possible deployment of renewable energy and the overall required support cost under the different policy instruments.

In Europe, there is a recent trend of providing financial support for renewable energy in form of Feed-in Premium (FIP) schemes instead of or in parallel to the previously

more commonly used Feed-in Tariff (FIT) schemes (Kitzing et al., 2012). In this paper, we analyse the differences of having a FIT scheme as compared to a FIP scheme for an offshore wind farm investor in the Nordic electricity system. Doing that, we can contribute to the discussion of what consequences a change from FIT to FIP could have on investor behaviour in the respective countries. On a broader level, we are investigating the choice of policy instruments and their impacts on private investors as well as society. Our results contribute to the in general still somewhat under-investigated question about how market prices, deployment of renewable energy, and overall support cost are impacted when a policy instrument is chosen that exposes investors to more market risk.

## C.2 Risk and Return

The relationship between risk and return is essential in decision making. As investments in renewable energy projects are typically very capital-intensive and long-term, a good understanding of the expected return and its probability distribution are crucial in order to justify a commitment of private investors into such projects. A pure cost-benefit analysis that only looks at the dimension of return can lead to wrong conclusions on the attractiveness of a project. This is illustrated in Figure C.1, where project B has not the highest return, but the best risk-return relationship.



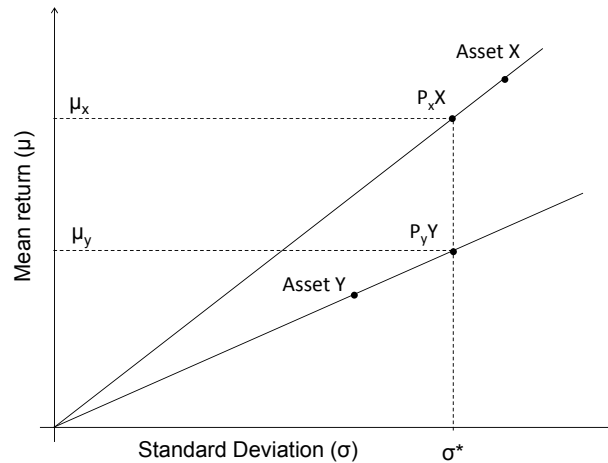
**Figure C.1:** Diverging conclusions of cost-benefit analysis and portfolio analysis

### C.2.1 Scientific background: Modern Portfolio Theory, Mean-Standard Deviation approach and Sharpe Ratio

In the framework of Markowitz (1952), expected returns and standard deviation are the only two variables that need to be considered in an investment decision: They sufficiently reflect the relationship between risk and return and can therefore be used to determine the relative attractiveness of any investment opportunity. This mean-

standard deviation ( $\mu, \sigma$ ) approach (or mean-variance approach) has been subject to a number of criticisms as discussed for example in P  zier (2011). One of the conditions in the mean-standard deviation approach is that the returns do in fact have a meaningful standard deviation, meaning that they are normally distributed or at least all return distributions have the same shape within a positive linear transformation (P  zier, 2011). This is by far not in all problems the case. Borch (1969) showed for example that in many cases, stochastic domination occurs for which the mean-standard deviation ( $\mu, \sigma$ ) approach would lead to wrong conclusions about the relative attractiveness of investments.

We choose to apply a mean-standard deviation ( $\mu, \sigma$ ) approach for our analysis as we can assume that the problem we are investigating stays within the carefully explained boundaries of the Sharpe Ratio, more specifically it can be expressed as a case of ‘adding a zero-investment strategy to an existing riskless portfolio’ as defined in Sharpe (1994). Here, we assume that an investor has a pre-existing portfolio consisting of a riskless security. We could consider adding an asset to this portfolio in order to increase the expected return while accepting a certain defined level of risk ( $\sigma^*$ ). When having to choose between two (mutually exclusive) investments X and Y which are both risky assets, the investor would naturally choose the strategy which results in the better risk-return relationship, which in this case is the combination of riskless security and asset X at risk level  $\sigma^*$ , in Figure C.2 illustrated as  $P_X X$ . Correlation is irrelevant here since the remaining holdings of the portfolio are riskless (Sharpe, 1994).



**Figure C.2:** Attractiveness of mutually exclusive investments [5]

The slope of such a line as illustrated in Figure C.2 is the Sharpe Ratio. The Sharpe Ratio thus measures quantitatively how well the return of an asset compensates the investor for a certain risk taken. The higher the Sharpe Ratio, the higher the reward for assuming risk, which makes an investment opportunity more attractive. The Sharpe Ratio is thus in effect a proxy for risk-adjusted return (Dowd, 2000). The

Sharpe Ratio  $S$  is introduced in its current form by the author in Sharpe (1994) as:

$$S = \frac{E[r - r_f]}{\sigma} \quad (\text{C.1})$$

where

$r$  is the asset return

$r_f$  is the risk free rate of return

$E[r - r_f]$  is the expected value of the excess return of the asset compared to the risk free rate

$\sigma$  is the standard deviation of the excess of the asset return.

From Equation (C.1), the connection to the Capital Asset Pricing Model (CAPM) (Sharpe, 1964; Mossin, 1966) becomes apparent. The CAPM gives a quantitative description for the risk structure of expected returns in the equilibrium. Combining the risk-free asset  $r_f$  with the market portfolio  $(r_m, \sigma_m)$  results in the Capital Market Line:

$$r^e = r_f + E[(r_m - r_f)/\sigma_m]\sigma^e \quad (\text{C.2})$$

where

$r_m$  and  $\sigma_m$  are return and standard deviation of the market portfolio

$r^e$  and  $\sigma^e$  are return and standard deviation of a portfolio (or asset).

The Capital Market Line has the ‘Market Sharpe Ratio’ as slope. In an efficient market, no portfolio of individual assets can have a greater Sharpe Ratio than the one on the Capital Market Line (Sharpe, 1964).

## C.3 Methods, Approach and Data

### C.3.1 Application of Modern Portfolio Theory

We use Modern Portfolio Theory as basis for our investigation of different support policy scenarios in the Nordic electricity system. We take the investment in an exemplary offshore wind park as a case and compare the attractiveness of investment under a fictive FIT and a FIP scheme. So in our application the mutually exclusive investments from Figure C.2 are 1) the wind park under a FIT scheme (‘Asset X’) and 2) the wind park under a FIP scheme (‘Asset Y’). We compare the Sharpe Ratios of these cases and draw conclusions on the relative investment attractiveness. Then we relate these results to the required support levels in each case and therewith can highlight one aspect of the overall efficiency of the support policy instruments.

### C.3.2 Return as key parameter of the analysis

For our analysis, we need to determine the expected excess return of the asset  $E[r - r_f]$  as a reflection of the ‘end-of-period’ wealth, which is one of the cornerstones in the mean-standard deviation methodology. We find this return by using a Cash flow model, in which we calculate the average return over the lifetime of the asset, i.e. the Internal Rate of Return (IRR). The use of the IRR measure entails several issues. The most relevant issue for our analysis is related to the reinvestment rate and financing rate of interim cash flows. The implicit assumption in the IRR measure of re-investing interim cash flows at the same rate of return as that of the project would lead to lopsided probability distributions in the results, as high returns would be leveraged by high re-investment rates. In order to cope with this issue, we apply the Modified Internal Rate of Return measure (MIRR) as introduced in Lin (1976). This is defined as:

$$MIRR = \sqrt[n]{\frac{-FV(CF^+)}{PV(CF^-)}} - 1 \quad (C.3)$$

where

$n$  is the number of equal periods at the end of which cash flows occur

$FV$  is the Future Value at the end of the last period

$PV$  is the Present Value at the beginning of the first period

$CF^+$  is the positive cash flows in each period, discounted at an explicit re-investment rate

$CF^-$  is the negative cash flows in each period, discounted at an explicit financing rate.

In our analysis, we assume both the re-investment rate and the financing rate to be at the level of the investor’s cost of capital.

Determining the cash flows in each period is the crucial part of this analysis. The cash flows of the offshore wind park in our case can be categorised into different groups as illustrated in Table C.1.

**Table C.1:** Cash flow types of an offshore wind park

	Year	Cashflows	Type
$CF^-$	0	Investment Cost	<i>deterministic</i>
$CF^-$	1-20	Operations and Maintenance Cost	<i>deterministic</i>
$CF^+$	1-20	Financial Support Scheme	<i>deterministic</i>
$CF^+$	1-20	Sales on Power Market	<i>stochastic</i>

We have chosen to treat Investment cost, Operations and Maintenance cost (O&M), and the support scheme as deterministic input parameters of the model. Investment

cost are often certain (at least to a large extent) at the time of investment decision. O&M cost are typically rather low and not very volatile for renewable energy technologies. We assume that the financial support schemes, i.e. FIT and FIP are determined by law and will be applicable throughout the lifetime of the project. We do not consider political risk of discontinued or altered support policies.

The stochastic modelling of cash flows from sales on power markets requires some more attention. In order to fully describe the power prices and their stochastic dependencies, an energy system model is required that integrates input data like resource availability (wind, hydro, solar), fuel prices, demand profiles, and available generation technologies with an optimisation algorithm that can compute the resulting power prices based on dispatching considerations from all market players. For our case, we apply the Balmorel model, which we have extended and modified so that it is able to perform stochastic simulations.

### C.3.3 Modelling of the Nordic Energy System: Balmorel

Balmorel is a model for analysing the energy system with emphasis on electricity and heat. It is a multi-period model with representation of years and detailed time resolution within the year. It has geographical entities representing district heating areas, electricity price regions linked by transmission interconnectors and countries for representing e.g. taxation and incentive schemes. The Balmorel model is optimisation-based with the possibility to minimise production cost and to maximise social welfare. The production system for electricity and heat includes a number of technologies, including wind, hydro and thermal production units and also storage possibilities for i.a. heat in district heating system and water for hydro power production. Further description of the model can be found in Ravn et al. (2001).

The Balmorel model is coded in the GAMS model language, and the source code is readily available (Balmorel, 2013). The Balmorel model has been applied in projects in Denmark, Norway, Estonia, Latvia, Lithuania, Poland, Germany, Austria, Ghana, Mauritius, Canada and China. It has been used for analyses of i.a. security of supply, the role of flexible demand, wind power development, development of international electricity markets and markets for green certificates and emission trading, expansion of transmission infrastructure, and evaluation of energy policy and renewable support schemes (Balmorel, 2013).

For this study, the Balmorel model has been used in a stochastic context on the supply side. For this, the model was extended to be able to cope with stochastic input parameters and to generate scenario tree calculations to perform Monte Carlo simulations.



### C.3.4 Data and assumptions used for the analysis

For a comprehensive system analysis, as we undertake with the Balmorel model, a number of input parameters have to be used. Electricity demand, district heating demand, the supply infrastructure including existing and planned power plants etc. are all deterministic input data, which are taken to a large extent from data provided by the Danish Energy Agency (DEA, 2012).

Stochastic wind production is modelled as random draws from 40 realistic weekly wind profiles, which are derived from historic production of offshore wind parks in Denmark (Balmorel, 2013). Volatility in fuel prices is still modelled in a rather crude way with a normally distributed probability function around the expected prices from DEA (2012). In the future, volatility in historic fuel prices should be investigated more in order to achieve a more realistic representation. With respect to hydro resources (that account for around half of the electricity generation in the modelled region) the annual inflow is modelled as random draws from values based on the last 20 years observed. Variations of wind resources, hydro resources and fuel prices are assumed uncorrelated.

Our input data for the offshore wind park are all based on DEA and Energinet.dk (2012), for an exemplary wind park in the year 2015 and are shown in Table C.2. The investment cost of 3.1 mEUR/MW is derived from the average of 13 planned offshore wind parks (in operation 2010-2013). We assume an operational lifetime of the wind park of 20 years.

**Table C.2:** Assumptions regarding the exemplary offshore wind park, based on DEA and Energinet.dk (2012)

Exemplary Offshore Wind park	
Capacity per turbine	4 – 7 MW
Total Capacity	360 MW
Full load hours	3850 h (after 96 % availability)
O&M cost	19 EUR/MWh
Nominal Investment cost	3.1 mEUR/MW

As starting point of our analysis of support schemes, we take a FIT scheme similar to the one that applies to the operating Danish offshore wind park Rødsand 2. This is a tendered feed-in tariff at approx. 94 EUR/MWh, which in the real case applies to 10 TWh of production corresponding to approx. 12-15 years of operation, and is constant in nominal terms (DEA, 2009). In the alternative policy scenario, we apply a FIP scheme, similar to the one currently applicable to Danish onshore wind parks. It is a fixed premium of approximately 34 EUR/MWh, which is paid out as add-on to the market price, also constant in nominal terms (DEA, 2009). In our exemplary case, we assume both support schemes to be applicable throughout the whole lifetime of the wind park, i.e. 20 years, and to be constant in real terms. Therefore, the resulting support levels are considerable lower than in reality.

Under the FIT scheme, the revenues from the wind park are subject to a guaranteed price throughout the supported period. The only major market risk remaining in the revenues considered in this analysis is the amount of wind power that can be sold at the guaranteed price. Under the FIP scheme, the revenues from the wind park are subject to market price risk in addition to the risk in the amount of wind power production.

As approximation for the risk-free rate, we use the long-term interest rates on Danish government bonds (10-year), which averaged at a nominal, pre-tax rate of 3.5% over the past ten years (OECD/IEA, 2008). This corresponds to a real interest rate of approx. 1.0% when applying an average inflation rate of 2.5% over the past ten years (DEA and Energinet.dk, 2012). Equity risk premium in Denmark averaged 4.1% (real) over the past ten years (2002-2011) (Credit Suisse, 2012). From this, we can approximate a real market rate of return of 5.1% to be used as benchmark in the further analysis.

### C.3.5 Steps of the analysis

We let the Balmorel model perform several different sets of Monte Carlo simulations. First, we look at a FIT support scheme and perform a system analysis for several different support levels. In a second step, we repeat the analysis for a FIP scheme. Each simulation provides us with information on the resulting wind production and power price level throughout the lifetime of the wind park. From these two results, along with our deterministic assumptions, we derive the total cash flows of the wind park in each simulation. Using the above described MIRR formula, we arrive at the expected return for the wind park. For each set of simulations, we then derive the expected mean return and the standard deviation of the returns. These are the major inputs to the subsequent financial analysis, in which we calculate the Sharpe Ratio for each set of simulations. In a last step, we compare the resulting Sharpe Ratios of each policy scenario to their respective support level. In this last step we not only show which support scheme would require higher support levels, we also quantify the difference for our exemplary case.

## C.4 Results

In the following, we discuss the results of our analysis for the exemplary offshore wind park in the Nordic electricity system under different policy scenarios. In principle, also other effects could be investigated using the results of the simulations, such as the effect of wind generation on the volatility of market prices and support payments. These shall be subject of further analyses using the newly developed stochastic Balmorel model.

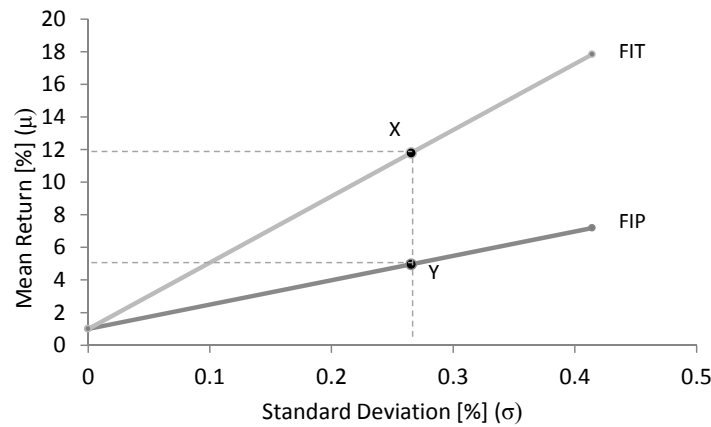
Table C.3 shows an exemplary result based on our simulations for the case in which

the FIT scheme provides an expected return (here represented by MIRR) of 5.1% (our previously defined reference point). In order to achieve this expected return, the FIT scheme must guarantee a price of 82 EUR/MWh. This corresponds to a support level of roughly 55.3 EUR/MWh, as the resulting average market price over the lifetime is 26.7 EUR/MWh. The latter is a result of the stochastic Balmorel simulations and an average over all simulation outcomes. Our simulations and post-analysis of the results show that the FIP scheme cannot provide an equivalent expected return at the same support level. In addition, the standard deviation (and thus the risk) is higher in the FIP case.

**Table C.3:** Returns, Standard Deviations and Sharpe Ratios under FIT and FIP schemes for the same support level (approximated simulation results)

	Feed-in Tariff (FIT)	Feed-in Premium (FIP)
<i>Support level</i>	<i>55.3 EUR/MWh</i>	<i>55.3 EUR/MWh</i>
Mean expected return	5.10%	4.96%
Standard deviation	0.249%	0.266%
Sharpe Ratio	16.4	14.9

In Figure C.3, we illustrate based on two different simulation results how much more attractive the wind park would be under a FIT scheme ('X') as compared to a FIP scheme ('Y'), when looking at the same risk level. Here the better risk-return relation of the FIT scheme becomes apparent.



**Figure C.3:** Resulting risk-return relationship for an exemplary offshore wind park under the two support schemes FIT and FIP, for  $\sigma = 0.266\%$

In order to make the support scheme equally attractive for an investor, he would require at least the same return under the different support schemes, and when he is risk-averse he would even require a higher return under the FIP scheme in order to be compensated for greater risk taken. The most obvious compensation strategy would be to provide additional financial support by increasing the support level in the FIP scheme as compared to the FIT scheme.

We are looking into that problem in two parts: First, we find the required support level of the FIP scheme that would match the expected return provided under FIT scheme. In a second step, we consider the risk-compensation by looking at the resulting Sharpe Ratios.

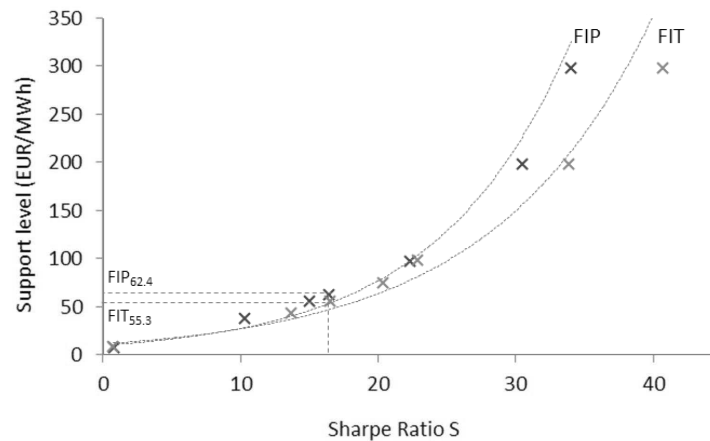
Table C.4 shows an exemplary result for this first part, i.e. where both expected returns are equal. Here we can see that the FIP scheme requires an approximately 4.5% higher support level to provide the same expected return.

**Table C.4:** Returns, Standard Deviations and Sharpe Ratios under FIT and FIP schemes for the benchmark return (approximated simulation results)

	Feed-in Tariff (FIT)	Feed-in Premium (FIP)
<i>Mean expected return</i>	5.10%	5.10%
Standard deviation	0.249%	0.265%
Sharpe Ratio	16.4	15.5
Required support level	55.3 EUR/MWh	57.8 EUR/MWh

Already here, we can clearly see that a support scheme providing the same expected return does not necessarily provide an equally attractive investment. For the FIT scheme, lower support levels are required and the Sharpe Ratio is higher. In this case, the FIT scheme is thus more attractive to an investor (because of the higher Sharpe Ratio) as well as to society (because of the lower required support payments).

Figure C.4 shows the differences in required support level dependent on the Sharpe Ratio. These differences are crucial for the second part of the analysis. From Figure C.4, we can read both required support levels for any given Sharpe Ratio, thereby ensuring that the two alternatives are equally attractive to an investor.



**Figure C.4:** Required support level over the Sharpe Ratio for the exemplary offshore wind park under the two support schemes FIT and FIP

Table C.5 shows an exemplary result for this second part, i.e. in which both Sharpe Ratios are equal. Here we can see that the FIP scheme requires significantly higher

support levels in order to provide the same Sharpe Ratios. We can also see that this level is higher than in the first part, where we only considered levelling out expected returns.

**Table C.5:** Returns, Standard Deviations and Sharpe Ratios under FIT and FIP schemes for the benchmark return (approximated simulation results)

	Feed-in Tariff (FIT)	Feed-in Premium (FIP)
<i>Sharpe Ratio</i>	<i>16.4</i>	<i>16.4</i>
Mean expected return	5.10%	5.33%
Standard deviation	0.249%	0.264%
Required support level	55.3 EUR/MWh	62.4 EUR/MWh

In the case shown in Table C.5, our exemplary offshore wind park would require an approx. 13% higher support level (62.4 EUR/MWh instead of 55.3 EUR/MWh) under a FIP scheme as compared to a FIT scheme. This stems from an approx. 6% higher exposure to market risk (standard deviation is 0.264% instead of 0.249%). The higher the Sharpe Ratios, the larger the difference between the required support levels of the two schemes.

We are aware that our resulting Sharpe Ratios would for any knowledgeable observer seem very high when compared to assets normally investigated in financial analysis. Indeed, our ratios by far exceed ratios of 3, which are usually already deemed as very good investments. Our high results naturally stem from the fact that, 1) we consider a longer time horizon than normally (average of returns over 20 years) and 2) we assume a strong support scheme that reduces risk exposure of the investor significantly as compared to other unsupported assets. In other words, wind parks under FIT are low-risk investments with returns that are typically still comparable to assets on market terms. However, this is a point that needs further investigation. Especially the impact of incorporating other kinds of risks into the analysis could be analysed.

## C.5 Discussion

This paper confirms, based on quantitative simulations, the intuitive hypothesis that investors of renewable energy projects would expect higher returns of their projects if they are exposed to more market risk. This is in itself no new conclusion, as such is the behaviour of all risk-averse investors. Renewable energy is however a special case as the related cash flows are typically to a very high extent dependent on policy support. Different types of policy support expose investors to more or less market risk. The type of policy scheme chosen by the policy makers is thus significantly affecting the return expectations of investors. This effect is much more significant for renewable energy projects than for most other common asset investments.

This insight can be used to help choosing the appropriate renewable support instru-

ment in a certain situation or to help determining the appropriate support level to be provided by a chosen renewable support instrument. For our case of an offshore wind park investment, we have shown that a FIP scheme would require a higher support level than a FIT scheme.

It can be argued that a similar analysis could have been made without drawing upon such a complex energy systems model as Balmorel. We did so because it was important to us to capture potential correlation effects of the stochastic wind energy production and the resulting power price. In any simpler analysis, i.e. based on partial models, the power price would always have to be an input parameter and the respective correlations and market effects could not have been captured adequately. This becomes especially problematic in an energy system with a high share of intermittent renewable energy, which the Nordic electricity system already is, and even more so will be in the future.

Further developments could be made in related future analyses. First of all, we would like to further validate many of our input parameters, especially regarding fuel price volatility. More flexibility could be added to our policy options. Currently, the offshore wind park in our scenarios is obligated to stay within the FIT support scheme, even on a price path in which the market prices are in periods rising above the guaranteed price. Additionally, we could increase the variety of investigated scenarios. E.g., it could be interesting to also investigate tradable certificate schemes.

## C.6 Conclusions

We have shown that policy design matters significantly for investors in renewable energy projects. The choice of support policy type is crucial for the rate of return that investors expect to achieve. A support scheme that exposes investors to more market risk will lead to an increased expected return.

We have made a stochastic analysis for the Nordic electricity system by conducting simulations with the energy system model Balmorel and applying the mean-standard deviation approach of modern portfolio theory to quantify risk implications of policy instruments for an exemplary offshore wind park. The analysis reveals that there exist different risk-return relationships for the two support policy schemes FIT and FIP, which result in different required support levels. In the investigated case, a FIP scheme would require an approx. 13% higher support level (all other things equal) than a FIT scheme, because of the approx. 6% higher exposure of investors to market risk.

Our findings can help when designing policy support, both regarding the type of policy instrument and the level of support, in order to ensure the effective and efficient development of renewable energies in Europe.

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PAPER D

# Support mechanisms for renewables: How risk exposure influences investment incentives

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Working Paper.



**Abstract**

*We analyse quantitatively how risk exposure from different support mechanisms, such as feed-in tariffs and premiums, can influence the investment incentives for private investors. We develop a net cash flow approach that takes systematic and unsystematic risks into account through cost of capital and the Capital Asset Pricing Model as well as through active liquidity management. Applying the model to a specific case, a German offshore wind park, we find that the support levels required to give adequate investment incentives are for a feed-in tariff scheme approximately 5-7% lower than for a feed-in premium scheme. The effect of differences in risk exposure from the support schemes is significant and cannot be neglected in policy making, especially when deciding between support instruments or when determining adequate support levels.*

**Keywords:** Investment risk; Support policies; Unsystematic risk; Liquidity management; Offshore wind; Feed-in tariffs

**D.1 Introduction**

Electricity generation from renewable energy sources (RES-E) is supported in many countries around the world. In the European Union, every Member State has established a dedicated policy programme for financial support of RES-E (Kitzing et al., 2012). Ever since the first support schemes were designed by policy makers some decades ago, there is an ongoing debate about which policy instruments and which design options are most suitable for an effective and efficient deployment of renewable energies.

This paper contributes to this debate by exploring risk implications of policy instruments and analysing the impact of policy choices on incentives for private investors. This perspective is especially relevant in liberalised markets. Here, policy making must ensure that adequate incentives are given to private investors so that specific RES-E targets can be achieved. To design effective and efficient policies, policy makers must look beyond costs and consider all aspects that are of concern for private investors, including effects on cost of capital and other risk implications (see also Gross et al., 2010). With such insight, policy makers are able to make informed decisions about required support levels and to evaluate the consequences of switching from one policy instrument to another.

In Europe, fixed feed-in tariffs (FIT) are the dominant policy instrument applied for the support of RES-E (Kitzing et al., 2012). With an increasing share of variable RES-E in the system and an increasing pressure to improve market integration of RES-E, many countries have now started to re-evaluate the use of traditional FIT schemes. Some have already implemented alternatives, mostly in form of feed-in premiums (FIP) (Kitzing et al., 2012). A counter-argument frequently put forward

against FIP is that this instrument exposes RES-E investors to higher risk (see Klessmann et al., 2008). In light of the ongoing policy trend in Europe and the related debate, this paper develops a general approach to analyse implications of choosing support schemes that expose investors to higher market risks than before. We then use the developed approach to analyse the switching from a FIT to a FIP scheme and quantify the consequences regarding investment attractiveness and required support payments for the case of an offshore wind investment in Germany.

The developed model aims at a theoretically consistent approach, drawing from different aspects of financial theory, along with an empirically sound parametrisation. The standard model for dealing with risk in investment analysis is the Capital Asset Pricing Model (CAPM), developed by Sharpe (1964), Lintner (1965), and Mossin (1966), which determines systematic risk and cost of capital based on the correlation of asset return with the market. We consider systematic risk based on the CAPM approach. In addition to that, we also consider unsystematic risk. We diverge from the standard approach here by assuming that investors may accrue cost from avoiding financial distress. In this, we draw from the approach developed by Schober et al. (2014).

The contributions of this paper are threefold: 1) We expand the framework of Schober et al. (2014), who assessed the impact of unsystematic risk via liquidity management for a single year, by developing a multi-year approach; 2) We apply the framework to a new area, namely investments in renewable energy projects under different support schemes; 3) We quantify the consequences of different risk exposures for a concrete case, an offshore wind park in Germany.

The remainder of the paper is structured as follows. In Section D.2, we describe the background for our analysis, including the relation to financial theory, the general DCF approach and the relevant support instruments. In Section D.3, we introduce our methodology, including the model structure, the modelling of stochastic processes, the modelling of liquidity management, and the beta analysis for the CAPM. In Section D.4, we apply the model to a specific case, namely a German offshore wind park in the Baltic Sea. We discuss the results in Section D.5 and conclude with Section D.6.

## D.2 General considerations: Investment risk

### D.2.1 Standard financial theory and systematic vs. unsystematic risk

A basic assumption of standard financial theory and portfolio selection theory is that risk and return are the only - and equally important - factors to consider in investment appraisal (Markowitz, 1952). Later, Sharpe (1964) and Lintner (1965) showed that firms should only be concerned with systematic risks when considering investment in new assets. This is, because it is assumed that perfect portfolio diversification can be obtained at shareholder level without transaction costs. This also implies that a firm should not undertake costly measures to avoid bankruptcy as, in perfect markets without transaction costs, old firms can go bankrupt and new firms can be established immediately at no loss. In reality, however, costs of bankruptcy can be substantial and irreversible (Bris et al., 2006): They can include loss of market share, inefficient asset sales, foregone investment opportunities, and more. Firms are thus often willing to undertake costly measures to avoid economic and financial distress (Davydenko, 2012).

In newer developments of financial analysis, also risks other than systematic market risk are being acknowledged. Further risk factors are incorporated into the analysis, e.g. in the three-factor model by Fama and French (1993), with the argument of market imperfections (and consequential diversification constraints), as well as transaction costs that make such types of risk costly. The choice of model can have significant implications on the valuation of investment projects. Empirical studies have found that required returns on equity may differ by 2% and more between the CAPM and the Fama-French-Model (Fama and French, 1997; Schaeffler and Weber, 2013).

Also for renewable assets, we expect that both systematic and unsystematic risks are relevant for investment decisions, because of transaction costs and irreversibility effects. In the presence of transaction costs, the generally agreed assumption of financial theory that investors are risk-averse (see Arrow, 1965) predicts that investors are willing to take action against risk exposure, by implementing safety measures - even if costly. We acknowledge that failures (e.g. bankruptcy) are costly to investors, and incorporate them into the analysis.

Our model is based on a net cash flow approach with risk modelling at two levels: 1) systematic risk, which stems from market risks and influences the cost of capital; and 2) unsystematic risk, which affects the required capital basis for an investment. More specifically, we assume that firms use liquidity reserves to mitigate their exposure to risk of financial distress. A greater variation in profit will generally require higher liquidity reserves. We thus expect that a support mechanism which mitigates

variation in profits the most leads to the lowest required liquidity reserves and thus highest expected returns.

A challenge with unsystematic risks is, however, that they are mostly in-transparent and specific for an individual firm. We therefore revert to an application case showing the concrete effects in a specific setting.

### D.2.2 Discounted cash flow evaluation of an investment

The standard method for evaluating investments is the discounted cash flow (DCF) approach (see e.g. Brealey and Myers, 2003). In this approach, all positive and negative cash flows related to the respective investment project are estimated, discounted with the applicable rate for the cost of capital, and summed up, as shown in Equation (D.1):

$$NPV = -I_0 + \sum_{t=1}^T \frac{R_t - C_t}{(1+r)^t}, \quad (\text{D.1})$$

where  $I_0$  are the investment costs,  $R_t$  are the revenues,  $C_t$  are the operational costs,  $r$  is the discount rate (cost of capital), and  $T$  is the project lifetime.

If the resulting net present value (NPV) of a project is positive, then the investment should be undertaken. Since many of the different elements contained in the future positive and negative cash flows are not known with exactitude, they have to be estimated. To account for the uncertainty, many investors include probability distributions of underlying elements in their assessment. This is done by e.g. creating different scenarios or making Monte Carlo simulations.

In principle, all three basic cash flows, namely revenues  $R_t$ , operational cost  $C_t$ , and investment cost  $I_0$ , can contain uncertainties. We simplify subsequently by assuming that at the time of investment decision,  $I_0$  and  $C_t$  are known and fixed. This may e.g. be achieved through fixed price contracts. Future revenue streams  $R_t$  are however uncertain and can cause variations in the returns from the project, which induces risk.

Traditional DCF analysis is based solely on standard financial theory and the assumptions underlying the CAPM in which only systematic risk is relevant. Systematic risks are exclusively dealt with through the cost of capital  $r$ . We have argued above that also unsystematic risks should be accounted for in our type of analysis. We do this by considering the prevention of bankruptcy through liquidity management.

### D.2.3 Liquidity management: cash reserves in firms

When considering unsystematic risks in form of risk of default or bankruptcy in a firm, one should distinguish between economic and financial distress. Economic distress occurs at low market asset values relative to debt and causes insolvency. Financial distress occurs at low cash reserves relative to current liabilities and leads to illiquidity. Usually, a firm defaults because of both factors, but this has not necessarily to be the case. Davydenko (2012) shows that 13% of defaulting firms in his sample were insolvent but still liquid, and 10% of defaulting firms were illiquid but still solvent. In our theoretical model, we focus on the indicator of financial distress (and firms avoiding illiquidity), acknowledging the simplification made. Moreover, we simplify by assuming that risk of financial distress represents all unsystematic risks in a firm. Knowing that there might be additional sources of costly unsystematic risk, our results can only establish the lower boundary for such costs. This approach corresponds to the one taken by Schober et al. (2014).

One way to deal with risk of financial distress is liquidity management. Liquidity management can take the form of either expenses for costly hedging (in order to reduce the risk of low revenues for the firm) or provision of an additional capital buffer in the firm (Schober et al., 2014). We understand liquidity management as the decision to upholding an optimized level of capital buffer within the firm to prevent defaulting, i.e. the going concern in possible illiquid states. A firm has several options to create a capital buffer: 1) secure bank lines of credit; 2) establish sufficient cash reserve in the beginning of a risky project; 3) raise required capital in the short term from shareholders (through retained earnings or equity injections).

As discussed by Flannery and Lockhart (2009), uncertainty about access to funds in the future (including from banks) might lead to excess cash holdings in a firm. Bates et al. (2009) give an overview of the literature's theories of holding excess cash in firms and show empirically that excess cash holdings in firms are common. Thus, we focus on cash reserves and capital from shareholders in this analysis (and not bank lines of credit). Because of the time-value of money and tax effects of cash holdings, a firm will however consider it optimal to build up cash reserves as late as possible. This corresponds to the conclusions of Acharya et al. (2007), who find that constrained firms are more likely to save cash out of cash flows. Therefore, we focus on the third of the above mentioned options, in which firms raise capital as late as possible either through retained earnings (i.e. by saving of incoming cash flows during operations) or, whenever necessary, by additional equity injections. This implies that a firm will strive to keep the liquidity reserve in any year as low as possible - just at the level needed to avoid financial distress in the next period with sufficient probability. It should be noted that liquidity management through cash reserves in the firm can at best decrease the risk of financial distress to a desired level, but can never eliminate it completely.

### D.2.4 Support schemes and investment risk

Several different policy instruments can be used to provide financial support for renewable energy projects. These span from investment grants over tax breaks to generation-based support. The latter type is dominant in Europe (Kitzing et al., 2012). Here, one can distinguish between instruments that expose renewable producers to market price risks and those that eliminate or at least reduce market price risks. During the early implementations of renewable support, mostly those instruments were applied that shield renewable producers from market price signals and thus also market risks (Kitzing et al., 2012). These are for example fixed feed-in tariffs, where renewable producers are guaranteed a fixed price for a certain period (e.g. 20 years). Equation (D.2) illustrates the revenue flows under a feed-in tariff scheme:

$$R_t^{FIT} = q_t FIT \quad (D.2)$$

where  $q_t$  is the renewable energy production volume per time period and  $FIT$  is the long-term guaranteed tariff level. Uncertainty stems here solely from the unknown production volume, which depends on the available renewable resources in time period  $t$ .

More recently, other instruments like quota systems with tradable green certificates or feed-in premiums are increasingly applied in Europe (Kitzing et al., 2012). In these schemes, support is paid out as market add-on. This means that renewable producers need to sell their production on the power market and are exposed to its risks. We focus here on feed-in premiums, under which revenues are determined as in Equation (D.3):

$$R_t^{FIP} = q_t(S_t + FIP) \quad (D.3)$$

where  $q_t$  is the renewable energy production volume in period  $t$ ,  $S_t$  is the power price, and  $FIP$  is the long-term guaranteed premium level. Uncertainty stems here from both the unknown production volume and the unknown market price.

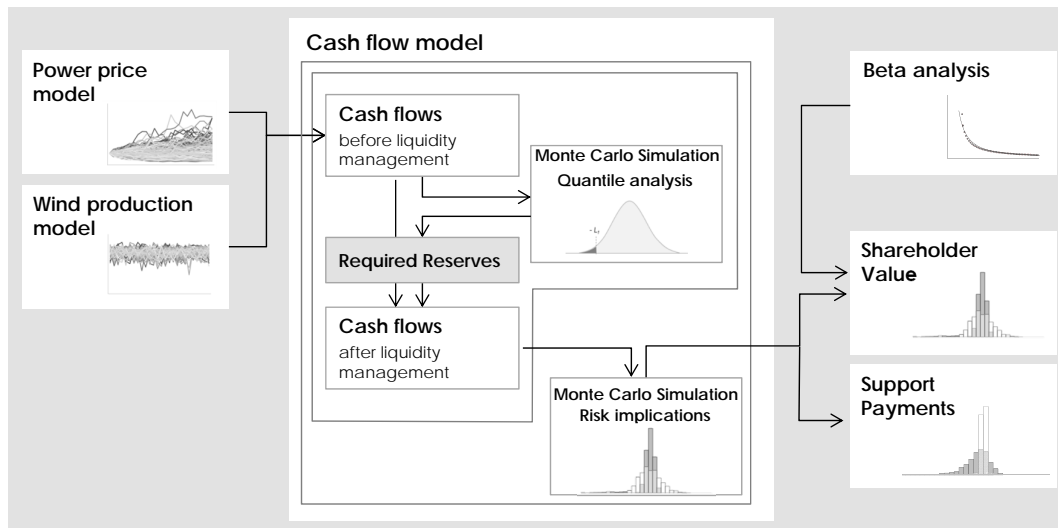
## D.3 Methodology

### D.3.1 Model structure

We develop a multi-year cash flow model that estimates the investment incentives for a wind energy investor under different risk exposures, and that incorporates dynamic

liquidity management. The purpose of the model is to determine a Shareholder Value (SHV) after liquidity management, which then can be used to compare the attractiveness of investment under different scenarios. For transparency reasons, we model a firm that has a single activity: the investment project throughout the lifetime of the project. This is also similar to creating a special purpose vehicle for a project. We thus assume that the SHV of this project/firm is the key determinant for the investment decision. Using the SHV, we can also derive the minimum required support level for the specific project, by assuming that the investment threshold is given by an ex-ante expected SHV of at least zero. Based on these two indicators (SHV and required support levels), comparisons between different support scheme designs can be made.

Figure D.1 illustrates the model structure. The model consists of several parts: a power price model, a wind production model, the beta analysis (estimating cost of capital), and the cash flow model (divided into cash flows before liquidity management and after). Two nested module functions undertake the required Monte Carlo simulations.



**Figure D.1:** Model structure

In the following sections, the different components of the model are explained in detail. Since we aim at deriving a multi-year investment assessment, we focus on the stochastic characteristics of annual quantities and prices, which in turn represent aggregates of shorter-term (e.g. hourly) values.

### D.3.2 Power price model

For modelling the annual average power prices, we use the two-factor model developed by Schwartz and Smith (2000). This two-factor model consists of a long term

process reflecting the uncertainty in the equilibrium price and a short term process reflecting stochastic shorter term deviations from the equilibrium price. The logarithm of the overall power price  $S_t$  is obtained as the sum of the two stochastic components:

$$\ln(S_t) = \xi_t + \chi_t. \quad (\text{D.4})$$

The long term process  $\xi_t$  expresses fundamental changes in the equilibrium level that are expected to persist, and reflects the natural logarithm of the long-run equilibrium level  $\bar{S}_t$ . Changes in this long-run equilibrium level may e.g. be related to changing fuel prices or modifications in the CO<sub>2</sub> regime. The developments over the last decade suggest that these changes are hardly predictable and that also in the future, substantial uncertainty will persist. The long term process then follows an arithmetic Brownian motion:

$$d\xi_t = \mu_\xi dt + \sigma_\xi dz_\xi, \quad (\text{D.5})$$

where  $\xi_t$  has drift  $\mu_\xi$  and volatility  $\sigma_\xi$ . This corresponds, according to Itô's Lemma, to

$$d\bar{S}_t = \bar{S}_t \left( \mu_\xi + \frac{1}{2} \sigma_\xi^2 \right) dt + \bar{S}_t \sigma_\xi dz_\xi. \quad (\text{D.6})$$

The long term process can be exactly discretised using an Euler scheme (Davis, 2012) to:

$$\xi_{t+\Delta t} = \xi_t + \mu_\xi \Delta t + \sigma_\xi \sqrt{\Delta t} \varepsilon_t, \quad (\text{D.7})$$

where  $\varepsilon_t$  is a random element with  $\varepsilon_t \sim N(0, 1)$ .

The short term process  $\chi_t$  expresses the mean reverting relation between the current price and the currently expected long term equilibrium:

$$\chi_t = \ln \left( \frac{S_t}{\bar{S}_t} \right) = \ln(S_t) - \xi_t. \quad (\text{D.8})$$

Its deviations are assumed to revert to zero following an Ornstein-Uhlenbeck process:

$$d\chi_t = -\kappa \chi_t dt + \sigma_\chi dz_\chi. \quad (\text{D.9})$$

where  $\chi_t$  has volatility  $\sigma_\chi$  and mean reversion coefficient  $\kappa$ .

The discretisation necessary for simulation is according to Phillips (1972)<sup>1</sup>:

$$\chi_{t+\Delta t} = \chi_t e^{-\kappa \Delta t} + \sigma_\chi \sqrt{\frac{1 - e^{-2\kappa \Delta t}}{2\kappa}} \bar{\omega}_t, \quad (\text{D.10})$$

<sup>1</sup> and not - as often done - using an Euler scheme, see Davis (2012)



where  $\bar{\omega}_t$  is a random element with  $\bar{\omega}_t \sim N(\rho_{\chi\xi}\varepsilon_t, 1 - \rho_{\chi\xi}^2)$  and  $\rho_{\chi\xi} \in [-1, 1]$  represents the correlation of  $dz_\xi$  and  $dz_\chi$ .

### D.3.3 Wind power production model

Wind production is modelled in a somewhat simplified setting by assuming that the wind production of one period is unrelated to previous or subsequent periods. We deem this approach appropriate when the model calculations are based on relatively large time steps  $t$ , such as monthly or yearly periods. Thus focusing on time-uncorrelated distributions, several studies emphasise the appropriateness of Weibull distributions. These are deemed most appropriate for estimating wind speeds and also wind energy production, see e.g. Villanueva and Feijóo (2010) or Carta and Velázquez (2011). We thus use a Weibull distribution, directly on the wind energy production. For the implementation in simulation, we use the quantile inverse cumulative distribution function:

$$q_t = P\lambda \left( -\ln(1 - \varepsilon_t) \right)^{\frac{1}{k}} \quad (\text{D.11})$$

where  $q_t$  is the stochastic wind power production in period  $t$ ,  $P$  is the average expected wind power production from the project,  $\lambda$  is the scale parameter of the Weibull distribution,  $k$  is the shape parameter of the Weibull distribution, and  $0 < \varepsilon_t < 1$  is a uniformly distributed random variable, corresponding to the quantile of the production distribution function.

### D.3.4 Cash flow model: before and after liquidity management

As mentioned above, we focus on the shareholder values and thus use the free cash flow available for shareholders  $FCFE_t$  as basis of the evaluation. We denote the sum of all discounted FCFE after liquidity management as the Shareholder Value (SHV). This indicator serves as the basis for comparing the investment incentives between different cases.

At time of investment ( $t = 0$ ),  $FCFE_0$  consists of cash flows from investment and financing activities. Total capital required at project investment is:  $\Omega_0 = I_0 + L_0$ , where  $I_0$  is the direct investment cost and  $L_0$  is the liquidity reserve that the firm has chosen to establish from the beginning of the project (if any).

We calculate the free cash flow available for shareholders before liquidity management

for each year  $t = 1 \dots T$  as:

$$FCFE_t = R_t - C_t - \theta_t - T_t + D_t \quad (\text{D.12})$$

where  $R_t$  are the revenues,  $C_t$  are the operation and maintenance cost,  $\theta_t$  are the interests paid for interest-bearing debt,  $T_t$  are the payable taxes (based on revenues, operational costs depreciation and interests), and  $D_t$  are the debt injections (if positive) or the debt repayments (if negative).

The revenues  $R_t$  depend on the production volume, on the achieved market price, and on the payments from the support scheme. The revenues under the two analysed support schemes are defined as in Equations (D.2) and (D.3). The operation and maintenance cost  $C_t$  are in our model deterministic and fixed costs, but in principle they can also be modelled as stochastic, if necessary. The interest bearing debt is calculated as follows: In the year of investment, a loan corresponding to a certain percentage of total investment  $\Omega_0$  is taken, which is then repaid on an annuity basis over a predefined amount of years.

The liquidity management is addressed through creating a cash reserve, here denoted the liquidity reserve  $L_t$ , which changes with  $\Delta L_t = L_t - L_{t-1}$ . The liquidity reserve must not become negative at any point in time during the project lifetime. As soon as  $L_t < 0$ , there is insufficient cash available and the firm experiences financial distress.

We calculate the free cash flow available for shareholders after liquidity management as:

$$FCFE_t^{LM} = FCFE_t + \Delta L_t \quad (\text{D.13})$$

The change in liquidity reserve  $\Delta L_t$  depends on the liquidity reserve still available in the ongoing year  $L_t$ , the expectation of  $FCFE_{t+1}$  and the risk appetite of a firm. In order to determine the required level of liquidity reserve  $L_t$  to avoid financial distress in the following year with sufficient probability, we apply a quantile computation analogous to the Value-at-Risk (VaR) calculation:

$$\eta = Q_{1-\alpha}(FCFE_{t+1}) = \sup \left\{ 1 - \alpha : P(FCFE_{t+1} < 1 - \alpha) \right\} \quad (\text{D.14})$$

where  $\eta$  is the level exceeded by  $FCFE_{t+1}$  at confidence level  $\alpha \in (0, 1)$ . We define  $L_t = \max\{0, -\eta\}$ . If  $\eta$  is positive, no liquidity reserve is required since the free cash flow is almost certainly positive and thus sufficient to satisfy all payment obligations. In contrast, a negative  $\eta$  implies that liquidity reserves are necessary to prevent financial distress.

We determine  $\eta$  by Monte Carlo simulations on  $FCFE_t$ . Assuming for example that the firm strives to avoid financial distress with a probability of  $\alpha = 99.73\%$  (the three-sigma rule), financial distress may only occur in 0.27% of the simulation paths in any year. From the simulation results, we determine  $\eta$  as the 0.27%-quantile of  $FCFE_{t+1}$ , from which we then derive the required liquidity reserve  $L_t$ . Depending on the level of the liquidity reserve in the previous year  $L_{t-1}$ , we subsequently determine the required change in reserve  $\Delta L_t$ .

After having determined the necessary liquidity reserve for each year, an additional set of Monte Carlo simulations must be undertaken for  $FCFE_t^{LM}$ . In outcomes where  $FCFE_{t+1}$  realises as  $FCFE_{t+1} > \eta$ , the excess reserve is paid out to the shareholders in each year, so that no cash is held in the firm other than the reserve required for the subsequent year. In outcomes where the liquidity reserve was not sufficient in a year, i.e. where  $FCFE_{t+1}$  realises as  $FCFE_{t+1} < \eta$ , the firm is assumed to immediately default. As a simplification we model this as if from this year onwards, all future cash flows in the defaulting simulation path become zero. This implies that we do not consider any final financial settlements and consider neither additional equity obligations nor pay-outs after bankruptcy of the firm.

### D.3.5 Model outputs: Shareholder Value and Support payments

The Shareholder Value is then determined as:

$$SHV = \sum_{t=0}^T \frac{FCFE_t^{LM}}{(1 + r_e)^t} \quad (D.15)$$

The free cash flows available for shareholders after liquidity management  $FCFE_t^{LM}$  are discounted with the cost of equity  $r_e$ , which is described in Section D.3.6.

The support payments are determined differently for each support scheme:

For FIP schemes with a fixed market add-on, the support level is straightforward: It directly corresponds to the guaranteed premium. The net present value of support payments (NSP) is for each simulation path calculated as the sum of the discounted yearly support payments, which corresponds directly to the project revenues from support:

$$NSP_{FIP} = \sum_{t=1}^T \frac{q_t FIP}{(1 + r_f)^t} \quad (D.16)$$

where we use the risk-free rate  $r_f$  to reflect the social time preference rate, as the

support payments are borne by society as a whole<sup>2</sup>. This ensures also a consistent comparison of the different cases.

For FIT schemes, the support payments have to be determined as difference between the guaranteed tariff and the market price:

$$NSP_{FIT} = \sum_{t=1}^T \frac{q_t(FIT - S_t)}{(1 + r_f)^t} \quad (D.17)$$

This relies on the following assumptions: (1) the market value of the electricity produced under the FIT corresponds to the current market price  $S_t$ , (2) this value is fully realised by the off-taking entity, and (3) the revenue from its market sales is entirely used to counterbalance the cost of support. Note that potentially, in years where the market price lies above the guaranteed price level, the FIT support costs can be below zero.

To obtain the equivalent FIT support level in real terms that is directly comparable with the FIP support level, the total support payments  $NSP_{FIT}$  are then divided by the total production and an equivalent real per unit price is computed using an annuity factor.

Besides the expected values, the Monte Carlo simulations also allow us to determine a probability distribution for all model outputs.

### D.3.6 Estimating beta and the support scheme-specific cost of capital

As mentioned above, we use the CAPM to describe the impact of systematic risk on the required return on equity. The expected rate of return on equity  $r_e$  is estimated by the CAPM as (see Brealey and Myers, 2003):

$$E[r_e] = r_f + \beta_e(r_m - r_f). \quad (D.18)$$

where  $r_f$  is the risk-free rate,  $r_m$  is the market return, and  $\beta_e$  is the equity beta.

The risk-free rate  $r_f$  and the market return  $r_m$  are general (not firm-specific) indicators and can be estimated by adequate long term government bonds and market

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<sup>2</sup>How societal risk preferences should be reflected in the used discounting factor requires further investigation. As the NSP serves subsequently only as a relative measure for comparing different support schemes, we leave this question for further research.

indices (such as the S&P500, Eurostoxx or DAX). The equity beta  $\beta_e$  describes to what extent the risks of a firm (in occurrence a project) are correlated with general market risks.

Generally,  $\beta_e$  is derived from historical observations using a two-step procedure: First, an asset beta  $\beta_a$  is determined from historical returns (on shares) using Equation (D.19):

$$\beta_a = \frac{Cov(r_a, r_m)}{Var(r_m)}. \quad (D.19)$$

This procedure can easily be applied for firms with publicly quoted stocks, using historical time series of their stock prices. However, we are not dealing with a stock-listed company but a specific investment project. We thus have to derive historical equivalent returns by creating a time series of profits for each support type. Since the price for FIT consists of a fixed tariff, there is no variation in returns. For FIP schemes, we create a time series from historical power prices, the fixed premium and a fixed level of operation and maintenance cost and depreciation. This reflects typical FIP ‘profits’, from which the returns can be derived. Using Equation (D.19), the asset beta  $\beta_a$  can be derived, comparing the obtained time series to the market index. Since the FIP time series becomes more or less volatile depending on the level of the fixed premium, the asset beta changes with the support level granted. This should be accounted for in any model application.

Second, the  $\beta_a$  needs to be re-leveraged to  $\beta_e$  based on specific firm characteristics, i.e. the debt/equity-ratio  $\frac{D}{E}$  and the tax rate  $r_T$ , using Equation (D.20) (Koller et al., 2010, p.713):

$$\beta_e = \beta_a \left( 1 + (1 - r_T) \frac{D}{E} \right) \quad (D.20)$$

The resulting ‘geared’ beta  $\beta_e$  can be used to calculate the cost of equity using Equation (D.18).

For the data analysis, we use the closing price of each trading day from a (stock) market index and compare it to a closing price of forward electricity prices, which are then adjusted according to the support scheme. Here, closing prices of short term electricity forwards (e.g. one-year ahead) are used as basis, acknowledging that the life-time value of a project does not only depend on short term electricity forwards, but on the longer term electricity price evolution. Yet data and our empirical estimation of the power price model suggest that one-year ahead power futures already strongly correlate with the long-term price expectations. Therefore, changes in forward prices reflect changes in project value and can be compared to asset prices from stock markets.

## D.4 Case application: offshore wind project

Applying the developed model to a specific case, we chose an exemplary offshore wind project in the German Baltic Sea. We first introduce the assumptions taken for the cash flow analysis, then proceed to the beta analysis, and finally present the case results.

### D.4.1 Cash flow analysis

As basis for the cash flow analysis, we make a number of assumptions related to the specific implementations of the support schemes, the stochastic processes, and project specific characteristics.

#### D.4.1.1 Support schemes

As mentioned in Section D.1, feed-in tariffs and premiums are the two support schemes that are highly relevant in the current European discussion of energy policy development. We thus compare the two in our case.

We assume the FIT scheme to be a traditional price guarantee. This means that an operator of a renewable project receives a pre-determined, fixed price for each unit of electricity generated, independent of the market price. We do not allow temporary or permanent opting-out of the FIT scheme. We see this as simplification, as in some circumstances an opting-out might be attractive, e.g. when the market price becomes structurally higher than the guaranteed tariff. Such analysis is not in focus of our study, but it might be relevant for future investigation.

We assume the FIP scheme to be a pre-determined, fixed add-on to the market price for each unit of electricity generated. Neither the FIT nor the FIP prices are assumed to be index-regulated, i.e. they do not increase with inflation, but remain constant in nominal terms. In order to increase the transparency of results, we assume that the support in both cases is granted throughout the project lifetime. We do not *ex ante* assume a support level. We rather determine the minimum required support levels in each scheme as an output measure.

#### D.4.1.2 Calibration of the price processes

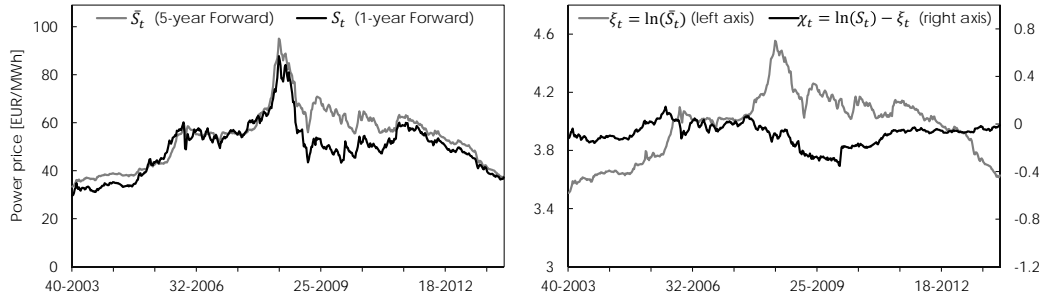
The two-factor Schwartz and Smith model is calibrated to the German power market. As basis for the calibration, we use German power forwards (Phelix Futures), more specifically the closing price on each trading day between October 2003 and September 2013 (EEX, 2014). The relevant prices of the 1-year Forwards and 5-year Forwards are shown in Figure D.2. Since the focus of the paper is not on advanced econometric estimation, we use rather straightforward calibration techniques for deriving the parameter values.

For the long term process, the drift and volatility parameters  $\mu_\xi$  and  $\sigma_\xi$  have to be estimated. We use 5-year Forwards as proxy, since these represent the longest time horizon on the German power market with at least some trading volume on a continuous basis.  $\sigma_\xi$  is estimated as the standard deviation of price differences  $\Delta\xi_t = \ln(\bar{S}_t) - \ln(\bar{S}_{t-1})$ , where  $\bar{S}_t$  is represented by the weekly time series of the 5-year Forward over ten years (from mid 2003 to mid 2013). The drift  $(\mu_\xi + \frac{1}{2}\sigma_\xi^2)$  is estimated by taking the average of  $\Delta\xi_t = \ln(\bar{S}_t) - \ln(\bar{S}_{t-1})$ , and hence  $\mu_\xi$  can be analytically derived from the formula. In a last step, the parameters must be annualised from weekly values using a factor of  $\sqrt{\Delta t}$ , whereby  $\Delta t = 1/52$ . We arrive at an annual drift of  $\mu_\xi = 0.00148$  and volatility of  $\sigma_\xi = 0.11402$ . As starting value  $\bar{S}_0$  for the simulation, we take the closing price of the last traded 5-year Forward of our time series, i.e. from week 36 in 2013, and obtain  $\bar{S}_0 = 37.65$  EUR/MWh.

For the short term process, the mean reversion coefficient  $\kappa$ , the volatility parameter  $\sigma_\chi$  and correlation parameter  $\rho_{\xi\chi}$  have to be estimated. We estimate the mean reversion coefficient  $\kappa$  from an ordinary least squares regression analysis of the time series  $\Delta\chi_t = \chi_t - \chi_{t-1}$  with  $\chi_{t-1} = \ln(S_{t-1}) - \xi_{t-1}$ . From the resulting weekly coefficient  $\alpha$ , the annualised mean reversion rate is derived using the relation  $-\ln(1 + \alpha)/\Delta t$  (cf. Equation (D.10)). We obtain  $\kappa = 0.5377$ . In an alternative approach based on Skorodumov (2008) that uses the property of half-life of a mean-reverting process  $t_{1/2} = \ln(2)/\alpha$  for estimating the mean reversion and a graphical analysis of the price process, we would arrive at a similar level of  $\kappa = 0.4806$ . We derive volatility  $\sigma_\chi$  by making use of the closed-form solution of the process, as described by Davis (2012):

$$\text{Var}[\chi_{t+\Delta t}] = \left(1 - e^{-2\kappa(t+\Delta t)}\right) \frac{\sigma_\chi^2}{2\kappa}. \quad (\text{D.21})$$

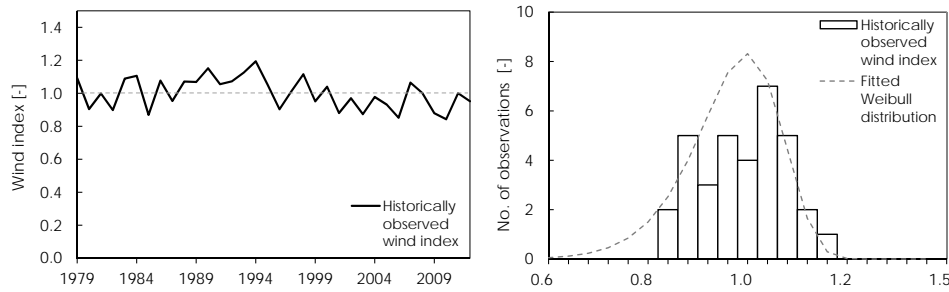
We estimate  $\text{Var}[\chi_{t+\Delta t}]$  from our time series through least squares linear regression. Inserting all parameters into Equation (D.21), we find the volatility of the short term process to be  $\sigma_\chi = 0.0976$ . To estimate correlation  $\rho_{\xi\chi}$ , we apply the standard statistical approach, using  $\rho_{\xi\chi} = (\sum_{i=1}^n (\Delta\xi_i - \Delta\bar{\xi})(\Delta\chi_i - \Delta\bar{\chi}) / ((n-1)\sigma_\xi\sigma_\chi))$ , where we have  $n = 520$  observations. The correlation is estimated to be  $\rho_{\xi\chi} = 0.1073$ . As starting value  $S_0$  for the simulation, we take the closing price of the last traded 1-year Forward of our time series, and obtain  $S_0 = 37.28$  EUR/MWh.



**Figure D.2:** Historical power prices, weekly, 1-year and 5-year Forwards from the German market (EEX), and the corresponding short-term and long term model processes

#### D.4.1.3 Calibration of the wind distribution

The wind model is calibrated to a historical wind index. The most comprehensive set of data available is from Denmark (EMD, 2013), which is a set of monthly values from 1979 to 2013. Since our model is based on annual considerations, we aggregate the data into yearly values. We assume that this data set is also applicable for a location in the German Baltic Sea.



**Figure D.3:** Historical wind production index, annual, 1979-2013 (EMD, 2013), and the fitted Weibull distribution

As described in Section D.3.3, the Weibull distribution is determined by scale parameter  $\lambda$  and shape parameter  $k$ . We use the maximum likelihood method for estimating the parameters, and obtain  $\lambda = 103.6$  and  $k = 12.05$ . The wind index obtained from the Weibull distribution is then multiplied with the expected annual wind production.

We estimate the expected annual wind production to be 4,040 MWh/MW at 100% availability, which is the expected average for a typical new large offshore wind park in the Baltic Sea, such as Kriegers Flak (DEA, 2012). At 96% availability, the expected electricity exported to the grid is estimated at 3,878 MWh/MW per year.



#### D.4.1.4 Project specific cost assumptions

The required project specific assumptions are investment cost, operational cost, project lifetime, depreciation rules, and income tax rate. Table D.1 summarises all estimates.

**Table D.1:** Project specific cost assumptions, based on 4C Offshore Limited (2013), PwC (2012), KPMG (2010), DEA (2012), and own calculations

Investment cost	3.01 mEUR/MW
Additional financing cost	0.86 mEUR/MW
Operational cost	106.8 kEUR/MW/y
Lifetime	20 years
Depreciation	straight line, 20 years
Income tax rate	28.1%

We estimate investment costs based on an average of the historical investment cost of all 45 commercial offshore wind parks in Europe (data collected from 4C Offshore Limited, 2013). Furthermore, we expect additional project financing cost, which we estimate based on information given in PwC (2012). Total upfront capital expenditures are thus estimated to be 3.87 million EUR/MW.

Empirical values for operational costs of offshore wind parks in Europe range from 20.2 EUR/MWh to 36.7 EUR/MWh (2010 prices) (KPMG, 2010, p.80). In reality, the operational cost are partially fixed and partially dependent on the production volume. We simplify by assuming fixed annual cost. We use the average value of KPMG (2010) transferred to 2014-prices and a per-MW-value, arriving at a fixed annual cost of 106.8 kEUR/MW.

The income tax rate in Germany comprises 15% corporate tax, 0.825% solidarity levy, and a local trade tax, which depends on the municipality the offshore wind park is assigned to. The federal State of Schleswig-Holstein e.g. suggests that local trade tax from offshore wind parks is to be paid out to the municipality of Helgoland (Ropohl, 2010), with a local tax rate of 12.25%. In total, we arrive at an income tax rate of 28.1%.

#### D.4.1.5 Assumptions on debt financing cost

Valuable information on financing of existing offshore wind parks in Europe can be found in KPMG (2010) and PwC (2012). In Table D.2, we present some relevant data for the (rather limited) experiences in Germany.

**Table D.2:** Financial data of real offshore wind parks in Germany (PwC, 2012, p.73)

Financial Close	Project	Capacity (MW)	Cost (mEUR)	Gearing (Debt share)	Tenor (Loan maturity) (years)	Margin
2011	Globaltech 1	400	1850	58%	15	3%
2011	Meerwind	288	1200	69%	15	2.5-3%
2010	Borkum West	200	780	59%	2+15	>3%

From the data of existing German projects, we can expect a debt share between 60% and 70%. Since this is such a decisive assumption for the case, we analyse different debt shares within this range.

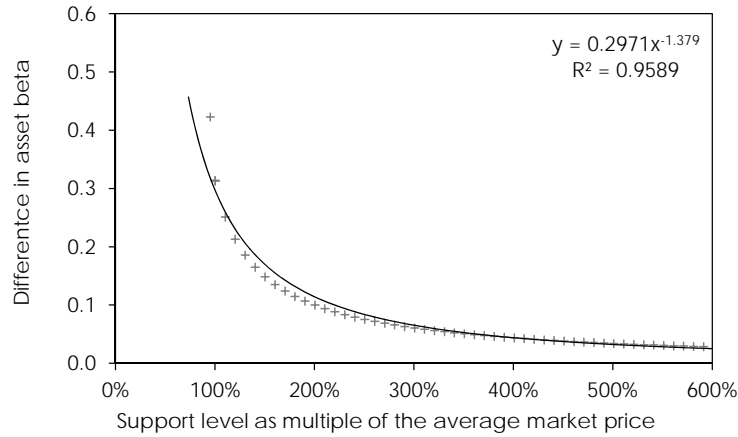
We assume that the project can obtain a 15-year loan. The total interest rate consists of a bank margin (2.5% to >3%), added to a (risk-free) reference rate. As reference rate, the interest rates for 10-year German government bonds can be used<sup>3</sup>. The ‘Bund 14’ was at 1.66% in January 2014 (Bundesbank, 2014). Often, a swap premium is also added (typically 0.2% to 0.5%) (PwC, 2012). We hence estimate the total interest rate to be 5.21%, consisting of 1.66% reference rate, 3.25% margin and 0.3% swap premium.

#### D.4.2 Beta analysis and cost of equity

As described in Section D.3.6, we start the beta analysis by determining the asset beta. We undertake the analysis based on historical developments of the DAX index (Bloomberg, 2014), as compared to returns composed of support payments and German one-year power forwards (Phelix Futures) (EEX, 2014). Annual costs are deducted from the returns, as described above. We have ten years of consistent data, from October 2003 to September 2013, with data on each trading day. Power price data before 2003 are not considered as being sufficiently reliable because of limited market liquidity in the first years after liberalisation.

From time series analysis, we find a positive correlation of the market index and the power prices. A FIT scheme, which eliminates this positive correlation through a fixed price guarantee, is expected to have an asset beta of zero. This can certainly be seen as a simplification, but is theoretically consistent in our approach. A FIP scheme partially decreases the positive correlation, to an amount depending on the support level: The higher the support level, and thus the fixed part of the income, the lower the correlation of return with the market. Figure D.4 shows the results of our analysis.

<sup>3</sup>German government bonds with 15 year duration are rather exceptional. Therefore 10-year bonds are used as best available approximation.



**Figure D.4:** Difference in asset beta of a FIP scheme as compared to a FIT scheme

Depending on the support level, we are now able to determine the beta, using the relationship depicted in Figure D.4. In order to estimate the equity beta  $\beta_e$ , we re-leverage the betas using Equation (D.20), specifically for each support level. For example, a FIP of 50 EUR/MWh corresponds to approximately 150% of the long-term average market price. The asset beta amounts to  $\beta_a = 0.11$  and the corresponding equity beta is then  $\beta_e = 0.24$ , with 28.1% tax rate and 60% debt share.

The results of our analysis correspond roughly to the findings of PwC (2012), who estimate that the introduction of a FIT mechanism in the UK will result in a 0.1 reduction of the asset beta.

We obtain the overall cost of equity by applying Equation (D.18). Here, we make a restriction: We assume that the cost of equity applied in the project appraisal cannot be lower than the total interest rate of the loan obtained for the project plus a margin. This reflects rational decision making by shareholders who would not accept a lower expected rate of return for their equity than the cost of debt. In fact, as the equity in a project involves greater risks than the debt, there should be a positive margin between the cost of equity and the cost of debt. We estimate this margin to be 2%, which is a conservative assumption when compared to Wallasch et al. (2011, p.99) and PwC (2012) where differences between cost of equity and cost debt amount 4-7%.

### D.4.3 Results of the case application

In order to test the significance of liquidity management for the results, we first analyse the case for a situation, in which no liquidity management is undertaken (Section D.4.3.1). Here, we assume that the firm can tolerate negative cash holdings,

e.g. through a bank agreement with short term loans or through a mother company guarantee. Subsequently, we analyse the same case including liquidity management (Section D.4.3.2).

The support levels are set so that in each case, a Shareholder Value of zero is reached, which is assumed to be the threshold of investment.

We show results for both a 60% debt share and a 70% debt share. We do this, because the assumption on debt share is, while rather uncertain, decisive for the results. Moreover, one could expect that the FIT can achieve higher debt shares than a FIP, because of the more stable cash flows. We thus also calculate a case where the FIT has a debt share of 70% while the FIP has a debt share of 60%.

#### D.4.3.1 Results without liquidity management

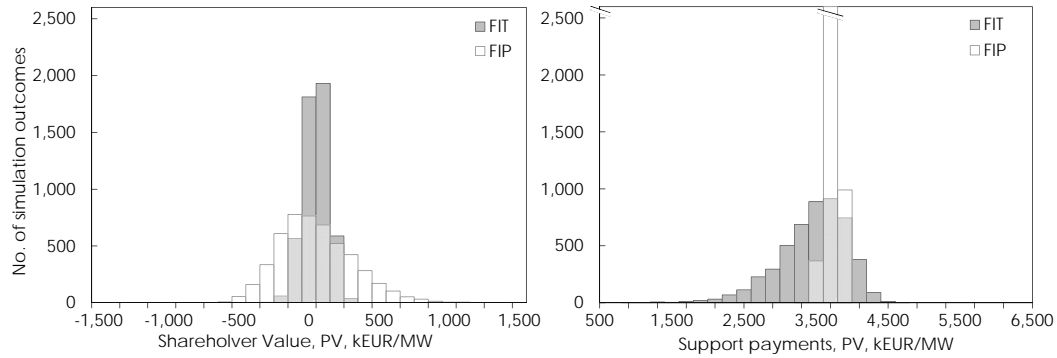
Having applied the model described above, we arrive at the following results in case the firm would not undertake any liquidity management. Table D.3 summarises all results for the undertaken variations in debt share.

**Table D.3:** Case results without liquidity management: Required support levels and their differences for three cases of debt shares

	<b>FIT</b>	<b>FIP</b>	<b>FIT</b>	<b>FIP</b>	<b>FIT</b>	<b>FIP</b>
Debt share	60%	60%	70%	70%	70%	60%
	<i>EUR/MWh</i>		<i>EUR/MWh</i>		<i>EUR/MWh</i>	
Tariff / Premium	123.5	87.3	121.2	85.4	121.2	87.3
Equivalent support level	83.1	87.3	80.7	85.4	80.7	87.3
Difference in support level	4.2		4.7		6.6	

The equivalent support levels of the FIT scheme are determined as described in section D.3.5. The support levels required to reach a Shareholder Value of zero differ between the FIT and the FIP scheme by 4.2 to 6.6 EUR/MWh, corresponding to 5-8% of total support. Figure D.5 shows the corresponding distributions of SHV and support payments for the third presented case. Obviously, the variation in shareholder value across the simulations is much higher in case of an FIP, whereas the variations in support payments are stronger for the FIT scheme.

The overall results are in line with the results of Kitzing (2014) who, based on a mean-variance approach, calculates a difference of 5-10 EUR/MWh between FIT and FIP, depending on the size of the support paid.



**Figure D.5:** Case results without liquidity management, for debt shares of 70% (FIT) and 60% (FIP), respectively

#### D.4.3.2 Results with liquidity management

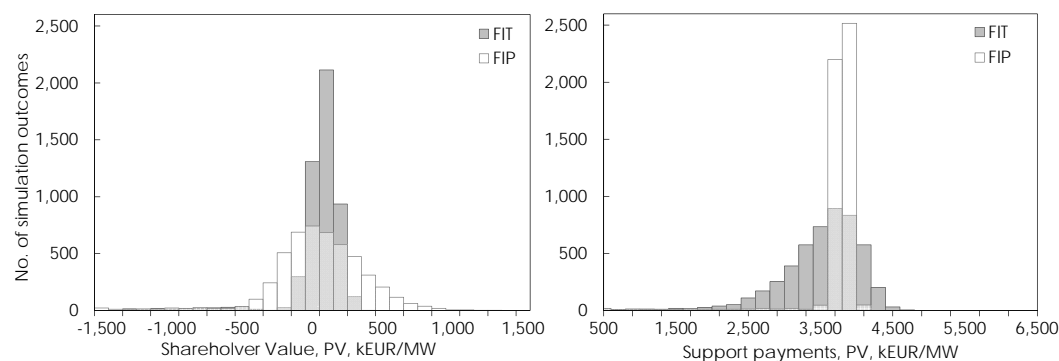
To capture more of the unsystematic risk in a theoretically consistent approach, we have introduced liquidity management in the firm, as described in Section D.3.4. Table D.4 summarises all results from the related case calculations.

**Table D.4:** Case results with liquidity management: Required support levels and their differences for three cases of debt shares

	<b>FIT</b>	<b>FIP</b>	<b>FIT</b>	<b>FIP</b>	<b>FIT</b>	<b>FIP</b>
Debt share	60%	60%	70%	70%	70%	60%
	<i>EUR/MWh</i>		<i>EUR/MWh</i>		<i>EUR/MWh</i>	
Tariff / Premium	125.3	89.1	123.6	88.0	123.6	89.1
Equivalent support level	84.9	89.1	83.2	88.0	83.2	89.1
Difference	4.3		4.8		5.9	

As expected, higher support levels are required than in the case without liquidity management, between 1.8 and 2.6 EUR/MWh. This is due to the cost related to holding the liquidity reserves. In our scenarios, the highest liquidity reserves are necessary under the FIP scheme with 70% debt share, where the cost of holding the reserve has a present value of 88 kEUR/MW, which corresponds to 53 million EUR for a wind park with 600 MW. In the same case, the FIT scheme would cause 4 million EUR less in liquidity reserves. Naturally, the cost of liquidity reserves are highest at high debt shares, as the increased debt service reduces the cash flows to shareholders.

The difference in support levels required to reach a Shareholder Value of zero now lies between 4.3 and 5.9 EUR/MWh, corresponding to 5-7% of the total support. Figure D.6 shows the resulting distributions for the third presented case, in which the debt shares differ.



**Figure D.6:** Case results with liquidity management, for debt shares of 70% (FIT) and 60% (FIP), respectively

For the first two cases, where debt shares are the same (60% and 70% for both schemes), the difference in required support level has slightly increased (by approx. 2%). This difference seems rather small at first. This is, however, due to another opposing effect: the higher support level stabilises the income from FIP as compared to the case without liquidity management, because now a smaller part of the income stems from the market and a larger part of the income is fixed. The FIP payment now makes 81% of the overall income, rather than 80% as before. The difference is only 1%-point, but it changes the profile significantly. Due to the higher fixed share in income, the beta is reduced (see the relationship depicted in Figure D.4), and thus the difference in cost of capital between the two schemes decreases. The reduced beta works in favour of the FIP scheme, whereas the liquidity management does the opposite.

The numbers from the 70%-debt-share-case may illustrate this point: Because of the higher support level required from introducing liquidity management, the average equity beta decreases from 0.217 to 0.208. Without this decrease in beta, the difference in support levels between the FIT and the FIP scheme would actually have increased even more, to 5.0 EUR/MWh. This was however overshadowed by the effect from the beta reduction before.

In the third case, where the FIT has a debt share of 70% and the FIP a debt share of 60%, the difference between the required support levels is actually reduced when considering liquidity management. This is due to the fact that here, the FIT needs comparably more liquidity reserves than the FIP, because of the higher debt share and the related lower cash flows available to shareholders.

Overall, we can conclude that in our investigated cases, most of the difference in support level stems from systematic risk, modelled through the beta differences. The addition of liquidity management is less significant, but it can be an important part of the analysis, as it counterbalances some reduction effects from changes in beta that could otherwise have led to an underestimation of the differences in required

support level.

## D.5 Discussion

### D.5.1 Comparison to the actual EEG tariffs

The German Renewable Energies Act (EEG) provides two different options of feed-in tariffs for offshore wind parks starting operation before January 2018:

1. An initial tariff of 150 EUR/MWh for 12 years plus a tariff of 35 EUR/MWh for the remaining 8 years;
2. An initial tariff of 190 EUR/MWh for 8 years ('optional acceleration model') plus a tariff of 35 EUR/MWh for the remaining 12 years.

The period for the initial tariff of 150 EUR/MWh is extended by 0.5 months for every nautical mile of distance to shore outside the 12-mile zone, and by 1.7 months for each metre of water depth exceeding 20 metres. We estimate that a park with a distance to shore and water depth typical for German offshore wind parks currently under development could realistically achieve 14 years of the higher initial tariff of 150 EUR/MWh, and then 6 years at 35 EUR/MWh.

Applying these tariff levels in our model, we obtain an internal rate of return for the project of 6.4%, which is in line with the rates of return of 7-9% that the German government assumes reasonable for wind parks (at somewhat higher assumptions on cost of debt) (see Wallasch et al., 2011). Hence, our model overall aligns with what is underlying official government policy in Germany.

In a next validation step, we compare the EEG tariff levels to our calculated ones, using the indicator of discounted net support payments over the whole lifetime of the project. These amount to 3.7 million EUR/MW for the EEG tariffs as compared to 3.4 to 3.5 million EUR/MW in our cases. We thus arrive at support payments that are equivalent to 92-95% of the actual EEG levels. Hence, our modelled tariffs of 121.2 to 125.3 EUR/MWh (that are assumed constant over 20 years) are comparable to the actual EEG tariffs (that are stepping down from 150 to 35 EUR/MWh after the initial period).

### D.5.2 Model assumptions and their consequences

We assume for transparency reasons and comparability of results that there is no opt-out option of the feed-in tariff scheme. However, we can see from the simulations in the case that in 4.7% of the price scenarios, a price occurs exceeding the lowest FIT level (of 121.2 EUR/MWh). In these situations, a RES-E producer would opt out of the FIT scheme and transfer into normal market operation had he the opportunity to do so. This has some consequences on our estimation of support payments, as they are estimated as the difference between guaranteed tariff and market price and can become negative. Had the FIT producer the option to leave the FIT scheme whenever the market price exceeds the tariff (and maybe even return to the FIT at a later point in time), no instances of negative support payments could occur. In this case, the netting approach adopted here would underestimate the overall support payments related to a FIT.

Assumptions regarding project-specific costs are also decisive for the results. We have used average values for all estimations. Specific parks can lie significantly higher or lower than that. This will have an effect on the required support levels and also on the absolute differences. However, since support schemes are usually not designed for single projects but a whole sector, our approach of taking an average wind park seems reasonable. Additionally, it could also be beneficial to test the consequences for a marginal park, i.e. the most expensive wind energy investment necessary to reach deployment targets.

The choice of power price process and its calibration also affects the results. Especially seasonal variations and jumps could have been modelled. However, we do not expect that incorporating these into the model would lead to significant changes in the comparative conclusions, because of the long time horizon of the analysis. We have confirmed that moderate changes in parameters of the short term process do not have any significant effect on the conclusions.

An issue still to be analysed is what the consequences are of having two different distribution types. The wind production model uses a Weibull distribution, whereas the power prices are assumed lognormal. Since the cash flows under the FIT scheme only depend on the wind production and not the power prices, the results under the two support schemes FIT and FIP are affected differently by the two distribution types. Especially the skewness factor differs between the two schemes. Whether this affects the comparison of the support schemes depends on the risk preferences of the decision makers. Here, further investigations are needed.



### D.5.3 Implications for policy makers

The model and insights generated in this study can help policy makers to determine appropriate support levels for renewable support schemes. This is especially relevant when switching from FIT to FIP schemes. Then, the support levels of the FIT cannot be directly transferred to the new scheme - they must be adjusted upwards to ensure continued adequacy of investment incentives.

In the recent past, policy makers in Europe are becoming more and more concerned with the burden of support schemes on consumers (Del Río and Cerdá, 2014). Policy making strives to limit total support costs to a minimum that can still provide the desired deployment of new renewable projects. In this, policy makers should be aware of the connection between required support level and risk exposure: The higher the risk exposure, the higher the required support level. As this analysis illustrates with a quantitative case, the effect of both systematic risk and unsystematic risk should not be neglected in policy making.

### D.5.4 Further development of the approach

In a first step, it could be beneficial to test the significance of several assumptions made. First, the loan maturity could influence the results significantly. We expect that the shorter the duration of the loan, the smaller the difference between the support schemes. Second, with technology development and further decreases in overall cost of offshore wind, also the support levels are expected to decrease. It could thus be beneficial to make a similar analysis with reduced support levels. We expect that the lower the support levels are, the larger the difference between the FIT and FIP scheme becomes, as volatile market prices become more dominant in the FIP case.

As the results are very sensitive to the assumed debt share, it would be of great advantage if these were not set exogenously, but could be determined endogenously. This could be e.g. done on the basis of probabilistic analysis of deficits in debt service, and limiting them to a certain level. We expect that here, the FIT could achieve higher debt shares, due to the more stable income flows.

Additionally, the model could be further expanded to cover other support instruments, such as tradable green certificate systems with quotas.

## D.6 Conclusion

This study contributes to the analysis of risk implications from policy instruments in several ways: First, we developed a multi-year approach to liquidity management in a firm in order to capture effects of exposure to unsystematic risks. Second, we adapted the framework to wind energy investment projects. Third, we quantified the policy consequences of choosing between feed-in tariffs and premiums for a specific case.

In an application case for a German offshore wind park in the Baltic Sea, we estimated that a FIP scheme would require 4.3 to 5.9 EUR/MWh higher support level in order to give the same investment incentive as a comparable FIT. This corresponds to about 5-7% of the total support payments. At the same time, the risk distribution both for investors and support payers is changed strongly.

Such risk implications should be taken into consideration when support policies are chosen and the respective support levels are determined. Otherwise, support levels might not be set at an adequate level, and the investment incentives experienced on the market could be quite different than what was intended by policy makers. This could lead to under-investment on the one hand, so that RES-E targets may not be achieved, or to over-investment on the other, so that total support cost are not easily predicted or controlled.

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PAPER E

# Regulating Future Offshore Grids: Economic Impact Analysis on Wind Parks and Transmission System Operators

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**Abstract**

*The increasing development of offshore wind parks in the European offshore territory may lead to meshed offshore grids in which each wind park might be connected to several countries. Such offshore grids could be subject to various regulatory regimes, depending on the degree of cooperation between the respective countries. This study focuses on how investors in wind parks and transmission systems are affected by the choice of regulatory regime in offshore grids with one to four countries connected. In order to capture the uncertainties related to the exposure to market prices as well as risks related to line failures, we develop a stochastic model for an exemplary wind park and offshore grid. This yields the real option values of operational flexibility from additional connections. Simulation results show that the choice of regulatory regime, including market access and pricing rules, can have a significant impact on the value of a wind park and on the value of the interconnection capacity in the offshore grid. The impact can both be positive and negative, implying a complex incentive structure for the involved actors. If contrary effects are not reflected in the remuneration level of a wind park, for example in the price premium level, investment incentives could either be diminished or the wind park could incur windfall profits. Both cases are socio-economically suboptimal as they may pose additional cost to the system. Policy makers should consider these findings when designing the regulatory regime and level of support in an offshore grid in order to maintain an effective and efficient development of offshore wind in Europe.*

**Keywords:** Economic impact analysis; Offshore grids; Offshore wind; Regulatory regime

## E.1 Introduction

Offshore wind energy is one of the cornerstones for achieving a higher share of renewable energy sources (RES) in a number of coastal European countries. Until now, the connection of offshore wind parks is mainly pursued from a national approach. However, with the increasing number of offshore wind parks in the European offshore territory, the interconnection of offshore wind parks in meshed offshore grids with simultaneous connection to more than one country is coming more and more into focus. An early example is the Kriegers Flak project in the Baltic Sea where Denmark, Germany and possibly Sweden at a later stage collaborate on a common offshore node. Similar projects are also under discussion for the Irish Sea and for the North Sea. A study on the latter demonstrated that a common connection of offshore wind parks as well as further connections between them can lead to large cost savings and extra benefits from electricity transmission of up to 21 billion Euro for the North Sea region (deDecker and Kreutzkamp, 2011).

An offshore grid would enable a joint system optimisation across wind parks, interconnections and electricity markets. This is expected to be of socio-economic benefit,

amongst others thanks to infrastructure cost reductions, increase in security of supply for all participating countries, enhancement of trade between markets, and benefits from an improved market integration of the fluctuating wind energy (deDecker and Kreutzkamp, 2011).

Offshore grids could be subject to various regulatory regimes, depending on the preferences as well as the degree of cooperation between the participating countries. More specifically, the countries would have to agree on the regulation of market access for the interconnected offshore wind parks and would have to design the pricing rules. Also the level of cooperation regarding renewable support and in some cases the choice of support scheme for the offshore area are to be considered.

Research in the field of offshore grids for wind energy is increasing: beside the aforementioned study by deDecker and Kreutzkamp (2011), research is undertaken on technical level, e.g. by Trötscher and Korpås (2011) regarding an optimal topology of an offshore network, as well as on regulatory level, where Roggenkamp et al. (2010) analyse offshore electricity grids and their potential implementation in respect to market and regulatory aspects. Woolley et al. (2012) analyse legal aspects of offshore grids, including the cases where an offshore wind park is in addition to its ‘home’ country also connected to one other, and where it forms part of a meshed offshore grid. Schröder (2012) shows that participation in national balancing markets constitutes a main part of the economic attractiveness of an offshore wind park and that an interconnection to several markets will impact the business case.

Most of these analyses deal with offshore grids from a macroscopic perspective. There is however a certain lack of understanding as of how the market actors, especially the investors in offshore wind parks and transmission systems, are affected by the choice of regulatory regime in an offshore grid. This understanding is of utmost importance when designing the regulatory regime in order to ensure adequate investment incentives for wind parks and transmission capacity. A step towards this understanding was taken in an earlier study by the authors (Schröder and Kitzing, 2012) and is further elaborated in this paper. We approach the research gap with a real-options approach: we investigate an offshore wind park in an offshore grid under different regulatory regimes and support scheme constellations, and determine the option value of operational flexibility for additional interconnections. With the further development and extension of the quantitative model, we now address the economic impact of different regulatory regimes on the investors and operators of wind parks as well as transmission systems.

Our model shows that there can be both positive and negative effects on the business case of the offshore wind park operator. We argue that the specific effects should be considered when choosing the regulatory regime and designing the support scheme in the offshore grid, in order to maintain the effective and efficient development of offshore wind in Europe.



The remainder of the paper is structured as follows: after an explanation of the investigated cases in Section E.2, we address the applied method in Section E.3. Then we turn to the quantitative results and their discussion (Sections E.4 and E.5). The paper concludes with qualitative conclusions and considerations on policy options (Section E.6).

## E.2 Possible regulatory solutions and pricing schemes in offshore grids

We investigate a fictive offshore wind park in an offshore grid, connected to between one to four archetypical European markets, with regard to different regulatory regimes and support scheme constellations. We consider two different support schemes: Feed-in tariffs and price premium mechanisms. Under Feed-in tariffs (FIT), a fixed remuneration per MWh is guaranteed and paid to the wind park operator for a fixed number of years (or generation hours). Selling the generation on power markets and correction of forecast errors is typically administered by the TSO, leaving the wind park operator with only limited market risk. Price premium mechanisms, or Feed-in premiums (FIP), are typically fixed add-on payments to the market price. The wind park operator has to sell the generated electricity on power markets and is exposed to both market price risk and forecast errors.

Since wind farm operators under feed-in tariffs are not exposed to significant market risk, market pricing rules do not play a decisive role in the investment decision. In the case of feed-in premium mechanisms, operators are exposed to market price signals and market pricing rules for the offshore grid become decisive. In extension to our previous analysis, we distinguish three fundamentally different regulatory regimes in terms of market access and spot market pricing rules:

1. **‘Home’ country:** The wind park in the offshore area is assigned to one ‘home’ country and has only secondary access to the other connected markets;
2. **‘Primary access’:** the offshore area is flexibly integrated into any of the neighbouring markets, so that the wind park operator has access to the respective maximum price;
3. **‘Offshore hub’:** the offshore area forms its own market price area and thus the wind park operator is subject to specific nodal pricing.

The first case depicts a situation of limited cross-country coordination, when for example the participating countries would like to benefit from the price-equalising effects of additional interconnection capacity between the markets, but are not co-operating at a higher level, such as regarding the support scheme. Then, an offshore

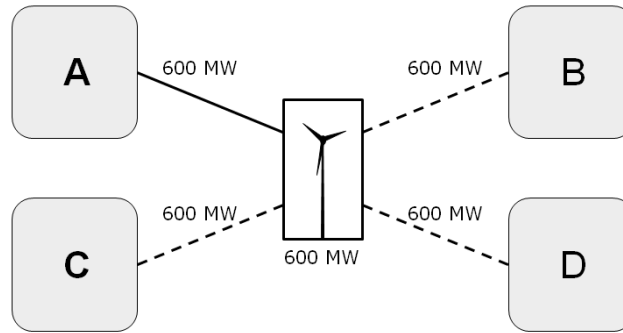
wind farm would be assigned one ‘home’ country into which it would primarily sell the power and receive the support. In case the market price in another country happens to be higher than the one of the ‘home’ country plus support, the wind park may choose to sell the power in that market. This is socio-economically not an optimal utilisation of the interconnection capacity as the price-equalising effect will be distorted by the support level. This effect is reflected by lower congestion rents collected by the transmission system operators (TSO).

The second and the third cases do allow an optimal utilisation of the interconnection capacity, as we here assume a support scheme specific for the offshore area, i.e. the wind park would receive a price premium no matter in which market the power is sold. The two cases differ in the pricing rules: In the second case, the production from the wind park is integrated in one of the neighbouring markets, and will receive the price of the respective market. The choice into which market to sell is left to the wind park operator. He will directly sell the produced power into any of the markets via a specifically reserved capacity in the interconnectors. The rest of the interconnectors are dispatched in implicit auctions. We refer to this case as the ‘primary access’ case.

In the third case, the offshore grid becomes an integral part of a larger market area with different price nodes (such as the Nord pool area), with implicit auctions on the entire interconnection capacities, and a separate price that may form in the offshore grid node in case of congestions. The offshore wind park operator will always be subject to the price that forms in the offshore node, which in many cases is equal to the lowest or a medium price of the neighbouring markets (Schröder and Sundahl, 2011). We refer to this case as the ‘offshore hub’ case with nodal pricing.

The number of countries (and therewith markets) that are participating in the offshore hub with respective interconnector capacities are decisive for the attractiveness of investment in an offshore wind park. In the benchmark case, only a connection to one market is assumed. We investigate the economic impact on the business cases for the wind park and interconnection cables induced by additional connections to other markets under all three regulatory regimes. Figure E.1 illustrates the different fictive connection situations distinguished in this paper: the benchmark case is a 600 MW offshore wind park connected to country A by a cable with the same capacity. This connection can be complemented by additional 600 MW interconnectors to the neighbouring countries B, C and D.

In addition to the connections, two other parameters are worth investigating: failure risk of any of the connections might impact the business cases significantly, depending on the regulatory set-up. Especially relevant for the stochastic analysis and therewith the option value is the strength of price correlation between the investigated markets.



**Figure E.1:** Overview of connection options in the considered cases

The above considerations lead us to the following cases we investigate during the remainder of the paper:

**Table E.1:** Overview of the analysed cases and their main distinguishing characteristics

	Benchmark	'Home' country case	Primary access case	Offshore hub case	Special cases
Geographical area	Country A	Countries A + B, C, D			
Renewable Support	Feed-in tariff Feed in Premium	Feed-in Premium (in Country A)	Feed-in Premium (joint scheme)		
Applicable price areas	Country A	Country A, and very high prices in countries B to D	Highest prices of countries A to D	Offshore price node (typically median of prices in countries A to D)	
Special events	-				Line Failures High market correlations

In order to capture the uncertainties related to the exposure of the offshore wind park to market price fluctuations under a price premium scheme and to integrate line failures into our considerations, a stochastic model is applied for the quantitative analysis. We use a real-options approach where any additional value related to the operational flexibility of being connected to other countries is regarded as the option value of the additional interconnection.

### E.3 Method

Market prices of the different markets are modelled as stochastic mean reverting Wiener processes, following well-established methods. Stochastic line failures are reflected by the authors' own approach, inspired by previous modelling of jump processes in commodity prices (see e.g. Hambly et al., 2009). We then compare the mean expected value of a wind park and its standard deviation in the different cases of regulatory regimes and country-connections to the benchmark case. This benchmark case is a wind park connected to one country only. At the same time, changes in congestion rents obtained by the involved TSOs for the different cases are analysed.

### E.3.1 A stochastic model for the value of a wind park under price uncertainty

We use a well-established and often used approach (based on Dixit and Pindyck, 1994) to develop a stochastic model of the spot electricity price in four countries, where electricity prices are a stochastic process following a Brownian motion. The stochastic behaviour of prices, including drift and volatility, are exogenously given to the model. It has often been shown that most commodities in general and electricity prices specifically show characteristics of mean reversion and seasonal patterns (Lucia and Schwartz, 2002). Considering the nature of the analysis, which is a comparison of different cases with the same underlying market price processes, we include mean reversion in the model, as it will indeed affect the results, especially because the cases are sensitive to small price differences between the countries. Seasonal patterns however are not expected to modify the comparative attractiveness of the cases significantly, as they would apply similarly to all countries. Therefore, seasonal patterns are not included in the model. The price processes are modelled as plain mean reverting Wiener processes after Dixit and Pindyck (1994). The stochastic change of price in each step  $dx$  is expressed with the mean reverting stochastic process:

$$dx = \kappa(x^* - x)dt + \sigma dW_t \quad (\text{E.1})$$

where

$W_t$  is a Wiener process with independent increments at  $W_t \sim W_s \sim N(0; t - s)$ , for  $0 \leq s < t$

$\kappa$  is the mean reversion factor of the market (exogenously given)

$\sigma$  is the standard deviation of the market (exogenously given)

$x^*$  is the ‘normal’ level of the price  $x_t$ , to which it tends to revert, i.e. the long-run marginal cost of production in an electricity system

The processes are Markovian, meaning that the distribution of future prices is only dependent on the present price and not the past history of prices, i.e. it follows fundamental signals. In this framework, the price  $x_t$  in each time step can be calculated from the previous price plus the expected change  $dx$  from a stochastic process:

$$x_t = x_{t-1} + dx \quad (\text{E.2})$$

For the simulation, we use the related first-order autoregressive process in discrete time (see Dixit and Pindyck, 1994, p.76):

$$x_t = \bar{x}_t(1 - e^{-\kappa}) + (e^{-\kappa} - 1)x_{t-1} + \epsilon_t + x_{t-1} \quad (\text{E.3})$$

where

$\bar{x}_t$  is the ‘normal’ level of  $x_t$ , to which it tends to revert.  $\bar{x}_t$  includes a drift in the process and is therewith also dependent on  $t$

$\epsilon_t$  is a normally distributed random variable with mean of zero and variance of

$$\sigma_\epsilon^2 = \frac{\sigma^2}{2\kappa} (1 - e^{-2\kappa}). \quad (\text{E.4})$$

Having the stochastic price processes for all four countries in place, we then model the hourly expected future cash flows of the wind park mainly dependent on revenues from sales into the different spot market based on the restrictions given by the different cases we investigate. Next, future cash flows are aggregated over the analysis period, i.e. the lifetime of the wind project, and a traditional discounted cash flow calculation is undertaken to determine the project value, here expressed as the internal rate of return in each scenario and each realisation of the stochastic price process (Brealey and Myers, 2002).

$$NPV = \sum_{t=0}^T \frac{CF_t}{(1 + IRR)^t} = 0 \quad (\text{E.5})$$

where

$IRR$  is the internal rate of return in each realisation of the price processes in each scenario

$NPV$  is the net present value of the wind park

$CF_t$  is net cash flow in period  $t$  (net of positive and negative cash flows)

$t$  is the time period of the Cash flow

$T$  is the number of periods, i.e. the lifetime of the wind park

Mean and standard deviation of the net present value of the project for the different cases are determined by a Monte Carlo simulation (N=1,000) capturing different realisations of the price processes.

### E.3.2 A model for stochastic line failures

Stochastic line failures are added as an optional choice to the model. We model the probability of occurrence of a line failure with a Poisson distribution  $P(\lambda)$ , which reflects the nature of the failures much better than e.g. a normal distribution. This modelling approach is comparable to modelling of jump processes in commodity prices (see for example Hambly et al., 2009). The probability of duration of the line failure is modelled as a normal distribution  $N(0; d)$ . We also add an exponential recovery process for the available capacity  $y_t$  when ramping up after the line failure, approaching exponentially to the maximum available capacity  $\hat{y}$ , the nominal capacity of the interconnection capacity between the wind park and the respective country.

$$y_t = \hat{y} - \hat{y}i_{(t,\epsilon)} - (\hat{y}j_{(t,\theta)} + (e^{-\kappa} - 1)y_{t-1} + y_{t-1}) \quad (\text{E.6})$$

where

$y_t$  is the value of available interconnection capacity, being restricted to  $0 \leq y_t \leq \hat{y}$

$\hat{y}$  is the nominal capacity, i.e. the maximum available interconnection capacity between the wind park and the respective country. It also serves here as the jump size in the Poisson process, meaning that the failure is expected to affect 100% of the capacity

$\kappa$  is the recovery rate of the exponential process towards the maximum available capacity  $\hat{y}$

$i_{(t,\epsilon)}$  is the variable that activates the line failure, with

$$i_{(t,\epsilon)} = \begin{cases} 1, & \text{for } \epsilon_t > 0 \\ 0, & \text{for } \epsilon_t = 0 \end{cases}$$

$\epsilon_t$  is a Poisson distributed random variable with mean of  $\lambda$ ,  $\epsilon_t \sim \text{Pois}(\lambda)$

$\lambda$  is reflecting the expected number of line failures per year

$j_{(t,\theta)}$  is the variable that activates the recovery process after an outage, with

$$j_{(t,\theta)} = \begin{cases} 1, & \text{for } t = t_p + \theta_t \\ 0, & \text{for } t \neq t_p + \theta_t \end{cases}$$

$t_p$  is the maximum value of  $t$ , in which a line failure last occurred, with  $t_p = t$  at  $\epsilon_t > 0$

$\theta_t$  is a normally distributed random variable with mean of zero and standard deviation of  $d$ ,  $\theta_t \sim N(0; d)$

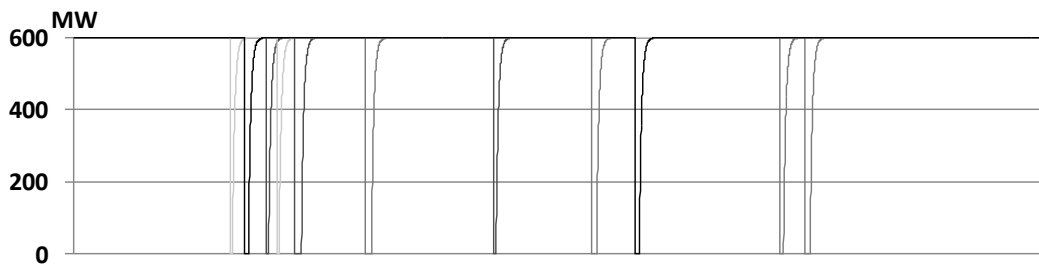
$d$  is reflecting the expected number of hours the outage lasts.

### E.3.3 Assumptions

As described in a previous section, we investigate a fictive case with four archetypical markets and a typically sized offshore wind farm of 600 MW. We assume the addition of 600 MW interconnectors to other countries as main distinction criterion between the cases. This has a crucial effect on results: the capacity of the wind farm is such that typically all its power can be sold into one market. Other capacity combinations, especially combined with different electricity price characteristics in the neighbouring countries, would most likely have a considerable impact on the results. This issue is dealt with in a sensitivity calculation, where we vary the connection capacity.

The electricity price processes for all four countries (see Section E.3.1) are assumed to share the same fictive stochastic parameters. The starting mean value is assumed at 50 Euro/MWh with a drift of +1 Euro/MWh towards the end of each year. The volatility is expressed as a standard deviation before mean reversion at 1.5 Euro/MWh, while the mean reversion coefficient  $\kappa$  is set at 0.01. Markets are non-correlated, except for one special case, where the effect of high market correlation is analysed by assuming a correlation of 0.9 of market A with B, C and D.

Regarding the stochastic line failures (see Section E.3.2) we assume that on average three annual interruptions occur with a normally-distributed duration with expected 50 hours per outage. The line failures are assumed to occur with a Poisson-distributed frequency with a  $\lambda$  of 3. The spike mean reversion parameter  $\kappa$ , reflecting the speed of return to nominal capacity after a line outage, is set at 0.05. The average failure duration of 150 hours per year corresponds to 1.7% outage per year, which is regarded to lie in a realistic range (Lindén et al., 2010 and Waterworth et al., 1998).



**Figure E.2:** Exemplary outage results for the four interconnectors over a full year

The wind time series is based on measured wind data at the FINO1 platform in the South-Western part of the German sector of the North Sea for the year 2006. It has been processed into an hourly production pattern accordingly to Nørgaard et al. (2004) and approximately adjusted for wake effects. The 600 MW offshore wind park is assumed to have a lifetime of 25 years, about 4,475 full load hours, investment cost of 2.45 million Euro/MW and operational expenditure of 0.07 million

Euro/MW/year. These assumptions on the offshore wind park are based on ENS (2010). Apart from the rather high value for full load hours derived from wind time series, these numbers are in line with Deloitte (2011) and assessed to be realistic for the nearest years to come.

## **E.4 Quantitative results**

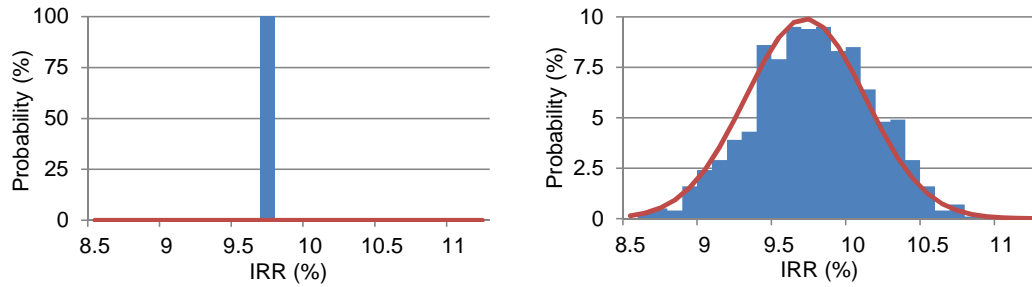
The quantitative results we obtain and discuss further are different for wind park and transmission system operators. For the offshore wind park, the Internal Rate of Return (IRR) represents the value of the wind park and therewith the investment incentive. We consider the expected mean IRR and the standard deviation of the IRR from the Monte Carlo simulations. For the TSO, the income from the interconnection operations forms the basis to evaluate the interconnections and therewith the investment incentive in additional cables. The TSO collects the income as congestion revenues, also called congestion rents, which are income from price differences on the participating spot markets and the implicit energy flows between them. We consider the expected annual mean congestion revenues as well as their standard deviation derived in the same Monte Carlo simulations as for the wind park.

### **E.4.1 One country – benchmark case**

In the benchmark case, the offshore wind park is only connected to one country and is thus fully integrated into that one market. In case the wind park receives a guaranteed price in form of a feed-in tariff, the wind park is not exposed to the volatility of that market and all Monte Carlo simulations result in the same IRR for the wind park (see Figure E.3, left). In case of a fixed price premium paid out in addition to the market price, the wind park is exposed to the underlying volatility and the Monte Carlo simulations yield a normally distributed outcome of the IRR (Figure E.3, right). We have designed the cases in such way that the expected mean IRRs for feed-in tariffs and premiums are the same in the benchmark case, namely 9.8%. The difference in attractiveness of the two cases lies in the different standard deviation – The higher the standard deviation, the higher the riskiness of the project. The Feed-in premium case yields in a standard deviation of 0.4%-points. This result forms the basis of comparison for our further analyses.

The congestion revenues for the TSO are assumed to be zero in the benchmark case, meaning that we only consider and compare the additional income generated by the new cross-border connections in the offshore hub in the two to four country cases.

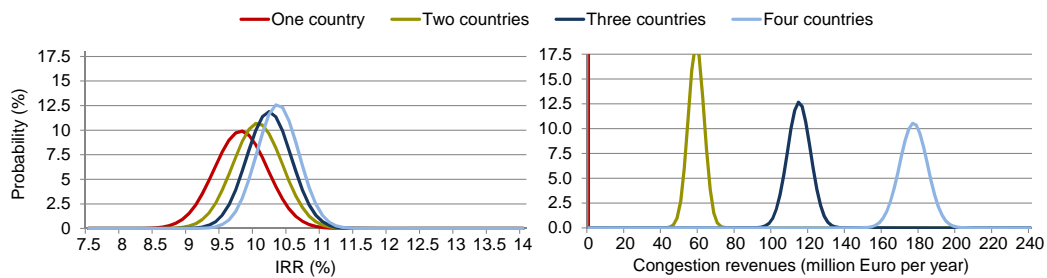




**Figure E.3:** Wind park IRR for feed-in tariff support (left) and price premium support (right)

#### E.4.2 Home country case

In this case, the offshore wind farm has primary access to its home country – where it is remunerated at the market price plus a price premium – and secondary access to the other countries, where it is only remunerated at the respective market prices. Quantitative results are depicted in Figure E.4 and show that the average IRR increases with the number of markets while the standard deviation decreases. The average IRR can be increased from 9.8% under the connection to one country up to 10.3% under the connection to four countries. The marginal benefit of each additional connection is decreasing. In addition to an increase in IRR, the standard deviation, which we use as indication for riskiness of the investment, decreases when adding more countries, in our simulations from 0.4%-points in the benchmark case to 0.32%-points in the four country case.



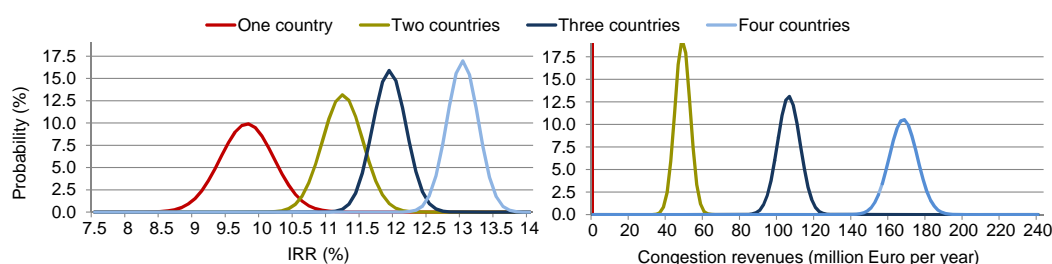
**Figure E.4:** Wind farm IRR (left) and TSO congestion rents (right) in the home country case

Considering congestion rents (Figure E.4, right), they increase with each additional connection and exceed the level achieved under primary market access by approximately 10 million Euro. The volatility, expressed as standard deviation of the congestion rents, increases from 4.3 to 6.3 million Euro when changing from two to three connected countries. Continuing to four connected countries, a further increase to 7.5 million Euro can be observed.

### E.4.3 Primary market access

In cases where primary access is chosen as regulatory framework, the wind park operator has full benefit from the additional connections, whereas the TSO can only use the residual capacity. The wind park can choose into which market it sells the electricity and can therewith achieve a higher income from choosing the highest price at any point in time – the more countries are connected, the higher the value of the wind park (see Figure E.5, left).

As already shown in Schröder and Kitzing (2012), the option to be connected to different countries increases the value of the wind park significantly. The value of the wind park is here expressed as mean expected IRR and increases with up to 33% in the four-country case compared to the benchmark case (up from 9.8% to 13.0%) when assuming a constant feed-in premium. In addition to an increase in IRR, the standard deviation decreases more than in the home country case, in our simulations with up to 42% (down from 0.4% to 0.24%). This is due to the fact that the wind park is less exposed to the volatility of market prices in one country as it has the option to switch sales to any other country whenever a low price period occurs. We conclude that the wind park operator will in this regulatory regime benefit from any additional connections: he can expect a higher IRR and at the same time a risk reducing effect. The risk-reducing effect is increased when taking line failures into account, whereas the expected project value and the risk reducing effect is decreased when considering correlation between the market prices of the participating markets. In our example, the IRR decreased by 0.6%-points when considering a two-variate correlation of all countries with country A.



**Figure E.5:** Wind farm IRR (left) and TSO congestion rents (right) in the primary access case

For all interconnector capacity that is not utilised by the wind park operator, the TSO collects congestion revenues from price differences in the adjacent markets. Figure E.5 shows the expected amounts and probability distributions for this income. Compared to the two-country case, the expected income increases with 119% in our simulations (+58 million Euro) when adding one more country, and yet another 61 million Euro to 167 million Euro with addition of the fourth country. This is due to the fact that in the chosen set-up, single interconnectors have the same capacities and

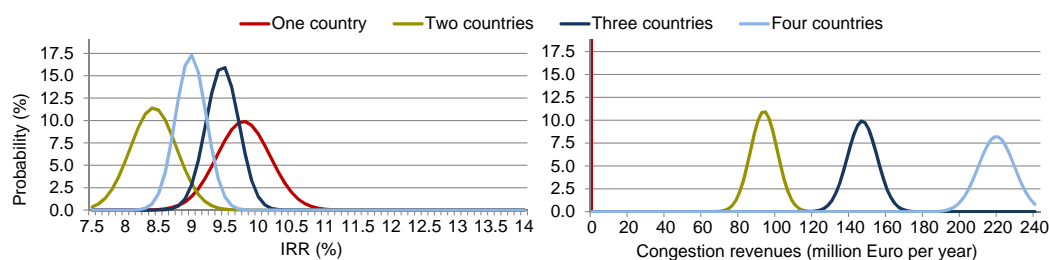
an even number assures a better asset utilisation than an odd number of lines. As an example, in periods without wind generation, one interconnector can export while another one imports. In a three-country case, this leaves the third interconnector idle. In a four-country case, the constellation is symmetrical again. Regarding volatilities, it becomes apparent from the simulations that – contrarily to the wind park operator – the TSO faces higher volatility in income when more countries are connected to the offshore hub. This is the case for markets with no or low correlation, since the additional volatility of each market adds to the overall fluctuation in price differences, which is the major income source for congestion rents. In a situation where the adjacent markets are highly correlated, both the level of income and the standard deviation decrease significantly.

#### **E.4.4 Offshore price hub**

In cases where the regulatory framework constitutes an offshore hub which forms its own price area, the wind park operator will not be able to choose on which market to sell his production. The offshore wind park will be subject to the price that forms in the offshore hub. This price is dependent on the price levels and price differences in the neighbouring markets as well as the overall available interconnection capacity. The flow in the connections from the wind park and the different countries is determined in implicit auctions. In almost all realistic situations, there will be at least one connection from the wind park to a country which is not congested, and the offshore hub price will thus equal the price of that market. This will typically not be the highest available price (Schröder and Sundahl, 2011). Therefore, the wind park will be valued at a lower level than in the case of primary access.

As was discussed in Schröder and Kitzing (2012), the model results reveal an interesting characteristic of how this regulatory framework impacts the wind park under the assumption of identical interconnector capacities. When two countries are connected to the offshore price hub, the hub will always form a price that corresponds to the lower of the two prices; therefore the impact is very significant with a decrease of ca. 15% (from 9.8% to 8.4%). In a case of three countries, the offshore price hub will form a price that corresponds to the median of all three prices. Some of the impact of the two-country case is mitigated. In a four country case, however a price will form that corresponds to the second lowest of the four market prices. In terms of riskiness of the project, i.e. standard deviation, the different country-cases show similar distributions as with primary access – a higher number of countries coincides with a lower standard deviation. The resulting IRR probability distributions are illustrated in Figure E.6. The differences of the cases are much less pronounced if there is significant price correlation between the markets of the countries especially when including periods of equal prices.

In the case of nodal pricing in an offshore hub, the TSO has access to the full



**Figure E.6:** Wind farm IRR (left) and TSO congestion rents (right) in the offshore hub case

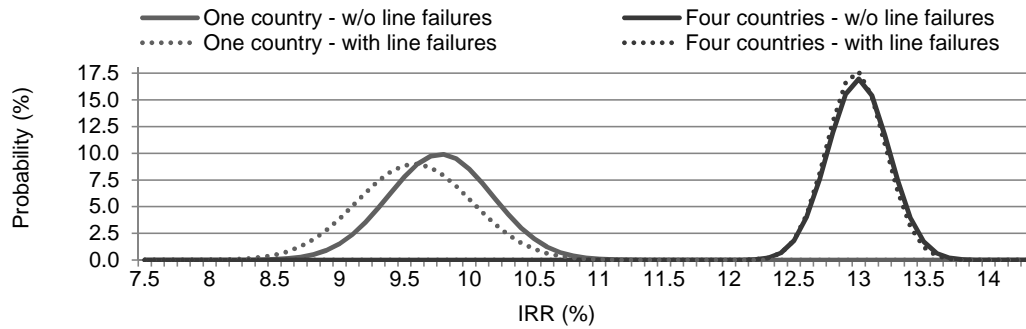
interconnection capacity as the production and energy flows from the wind park is integrated in the overall market. Therefore, the TSO is able to collect more congestion revenues – the increase is in fact the same amount of revenues that the wind park operator loses in the offshore hub regime compared to primary access. The annual revenues lie in our simulations for each country-constellation 45-52 million Euros higher than in the primary access case.

It can be noted that the two-country case, which is the least attractive for the wind park operator is not the best case for the TSO, as the TSO's revenues increase with addition of more countries simply because more energy flow becomes possible. Also, the connection to a fourth country is not beneficial for the wind park operator, where it is for the TSO. In these cases, opposing interests of wind park operator and TSO could hamper the (further) construction of an offshore hub.

#### E.4.5 Special case: line failures

Line failures are a special case for this analysis, as the loss caused by line outages is a real reduction in energy flows between countries. Here again, it is a question of the regulatory framework in who is exposed to a potential loss from line failures – the wind park operator or the TSO. If the wind park operator is not compensated for line failures of the offshore cables, he bears risk of income loss from not being able to sell the power he produces. Figure E.7 shows this situation for connection to one country on the left. If the wind park is connected to additional countries (each having similar risk of line failure) and has access to any of the other markets, then the wind park is less exposed to income loss the more countries are added, because it becomes less probable that all lines fail at the same time. Figure E.7 shows that the income risk is nearly fully mitigated by four connections. This finding is in line with Macharey et al. (2012), who analyse possible interconnections between single German offshore wind clusters and conclude that meshed offshore structures can, even within one price zone, have a considerably risk-reducing effect and be profitable.

This result can be of significant impact for the future valuation of wind parks in



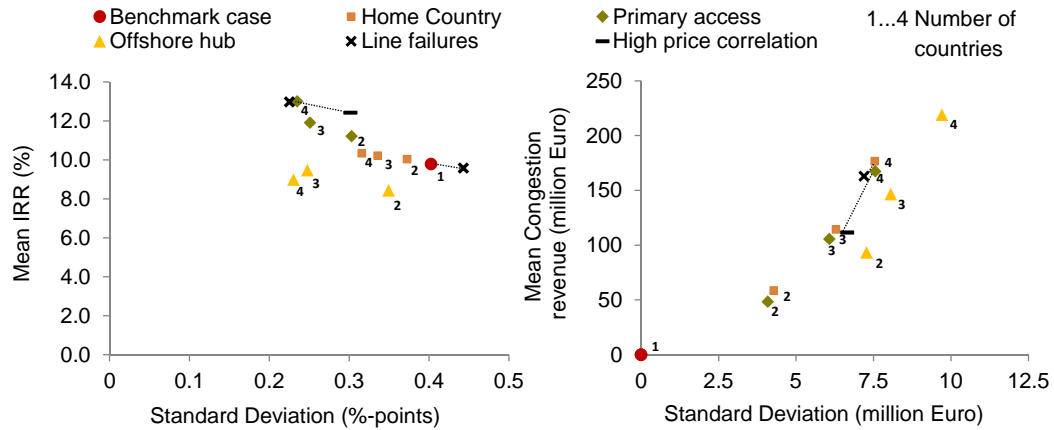
**Figure E.7:** IRR probability distribution changes for the wind park considering line failures

offshore hubs, especially in a regulatory regime with offshore hub pricing – the risk reducing effect on line failures might mitigate some of the disincentives for offshore wind park operators in the construction of an offshore hub. However, in a regulatory regime where wind park operators are fully or partly compensated for line outages, there will be no measurable or only limited impact on the wind park value. Here, the income for the TSO will, in addition to the losses from foregone congestion revenues, also be affected from the compensation payments for the wind park operator.

#### E.4.6 Comparison of all cases and sensitivity analysis

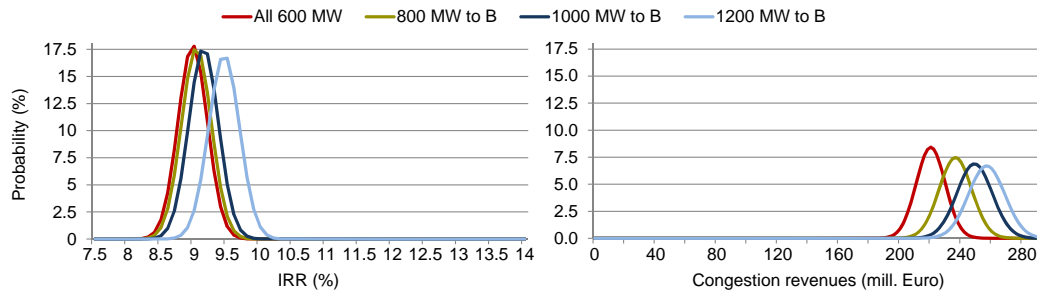
The overall comparison of all cases as illustrated in Figure E.8 displays that wind park investors and the TSO have opposing preferences in regards to the regulatory regime. The TSO benefits clearly from a nodal pricing system in the offshore hub (all ‘offshore hub’ cases (yellow triangles) have the highest mean congestion revenues), whereas the wind park operator would prefer a regime with primary market access (green squares). Line failures have a much lower impact on cases than a high market price correlation (both special cases are connected to their respective reference cases by lines).

The difference between primary access and nodal pricing is least pronounced for the three-country case: here, the primary access and nodal pricing cases differ only by 41 million Euro on average. The reason is a comparatively good case for the wind park under nodal pricing, which is at the expense of congestion rent income. This illustrates that option values between several cases are highly dependent on the underlying assumptions.



**Figure E.8:** Overview of all case results for the offshore wind park (left) and the TSO (right)

A sensitivity analysis for changed line capacities under nodal pricing shows that the wind farm's IRR standard deviation is only affected marginally, whereas the average return increases especially with the upgrade to 1,200 MW (Figure E.9, left). This is due to the fact that, starting with the benchmark value of 600 MW for all cables, the connection to one country has been increased in steps of 200 MW until 1,200 MW. Reaching 1,200 MW, the interconnection corresponds to two other interconnectors leading to a new price formation constellation, which explains the major difference to a capacity of 1,000 MW. Regarding the congestion rents (Figure E.9, right), the result fits with the expectation that additional interconnection yields decreasing marginal benefits.



**Figure E.9:** Wind farm IRR (left) and TSO congestion rents (right) for changed line capacities

## E.5 Analysis and discussion

The investigated cases do not represent real conditions in terms of markets or technical options, but they carry some pure and archetypical characteristics of conditions

for potential offshore grids in the European offshore territory. Therewith, they can serve as basis for the main points we wish to highlight. The results from the simulations show that the choice of regulatory regime has a decisive impact on the value of a wind park investment as well as for the income for transmission system operators. The impact can be both positive and negative for the different actors. Overall, we observe that the choice of regulatory regime in comparable cases, i.e. the primary access and the offshore hub case (with the same structure of RES support), has a re-allocative effect of benefits between the actors rather than creation of additional benefits. As long as connection capacities and market prices do not change between the cases, the aggregated benefits including the sale of wind power production and price differences between markets are the same. In case of primary access, more of the benefits are allocated to the wind park operators, and in the offshore hub with nodal pricing, more income is allocated to the TSO. Both regimes are feasible – it is a policy choice which regime should be implemented. In this regard, some considerations should be made.

First, offshore wind park are and will for the near future be dependent on financial support by specific instruments such as Feed-in tariffs or Feed-in premiums. If a regulatory regime is chosen that exposes the investor in offshore wind parks to market risk and at the same time to nodal pricing in the offshore hub, there is a significant risk of lower IRR when additional countries are added to the offshore hub. The attractiveness of investment is consequently decreased. In order to trigger an adequate amount of investment, the level of support needs to be increased. The higher support level could be paid from the additional congestion rents that the TSO incurs. By contrast, if a primary access regime is established, the wind park operator could benefit from significant windfall profits when additional countries connect into the offshore grid. To avoid socio-economically overly expensive support mechanisms, the level of support should be corrected downwards for each new country in the offshore grid.

Second, the level of cooperation between the countries needs to be taken into consideration. It will not always be possible to create an offshore hub with nodal pricing due to the high level of coordination. If one country has a well-established national Feed-in tariff system, only a strong ‘home’ country affiliation seems to be practically possible. However, an offshore hub regime with nodal pricing could especially become interesting for internationally coordinated support schemes in the future to ensure neutrality between the neighbouring countries (see Schröder et al., 2011).

In addition, the sensitivity analysis on interconnector capacities to different markets shows that quantitative results exhibit remarkable differences if the connection to one country reaches an integer multiple capacity of the capacities towards other countries. It should be emphasised that this also depends on the assumed generation time series and capacities.

We have limited our analysis to spot markets. In reality, balancing markets and their prices might be a very decisive factor in choosing on which market to sell. The cases and countries investigated do not represent a realistic market environment. Before drawing conclusions on real-world cases, the model should be calibrated to real market characteristics; especially the level and volatility of the markets are decisive. This, however, could first be applied for a real-world case where the interconnector capacities and market price characteristics are known and where the offshore node's generation is handled differently than national onshore generation. A main simplification is that we look at real option values for the whole lifetime of the project. This supports transparency, but would probably not apply in real-world cases: additional interconnectors are first decided upon after the offshore wind farm comes into operation. So, for more realistic cases, a sensitivity analysis on additional interconnectors only after a certain number of years would provide valuable insights.

## E.6 Conclusions

This paper presents an analysis on the economic effects of different regulatory regimes on offshore wind parks and transmission system operators in an offshore grid. Stochastic price processes and line failures are modelled for four spot markets. An offshore wind farm as part of a meshed offshore grid is connected to between one and four of these markets, experiencing different option values of additional interconnectors.

The analysis reveals two major insights: First, we have shown that the regulatory regime, including market access and pricing rules, has a significant impact on the valuation of assets in an offshore hub, both wind parks and interconnection capacity. The choice of regulatory regime can have both positive and negative impact on the actors. In our (fictive) case with connections to four similar archetypical power markets, the IRR for an investment in a wind park increases with up to 33% if the wind park has primary access to all markets. Contrarily, establishing an offshore hub with nodal pricing can have a negative impact on the IRR of up to 15%. So, the incorporation into an offshore grid is far from neutral for an offshore wind park. This leads to the question of how to compensate for possible losses or gains under the suggested regulatory mechanisms. Our results show this may need to be handled on an interconnector-by-interconnector basis: while the connection to a third country is beneficial for the offshore wind park under nodal pricing, the connection to a fourth country is negative.

Second, the incentives for the different market actors in relation to additional connections are very different and in some cases even contrary. This is particularly visible for the offshore price hub, where the wind farm's profit increases or decreases depending on the number of the connection to be made. It can contrarily still be a good business case to add a cable that is negative from the wind farm's point of



view. Thus, the market actors such as transmission system operators and wind farm operators may take very different positions towards establishing new connections at different stages in the development of meshed offshore grids – which may hamper the construction of new lines that are beneficial from a socio-economic perspective. Both effects should be considered in future valuations of wind parks and offshore hubs as well as in the design of the regulatory regime for the offshore grid and the level of support for the wind park. Only then, an effective and efficient development of offshore wind in Europe can be achieved.

The sensitivity analyses that we have undertaken regarding different interconnection capacities shows that minor upgrades for single interconnectors improve the wind farm's income only marginally. A larger improvement is reached when a capacity corresponding to existing capacities (600 MW in the example) is added. As expected, the marginal benefit of additional capacity decreases from a TSO point of view.

Our results can be used when considering how to design a cross-border offshore hub, such as envisaged in the Kriegers Flak area, to make an informed decision. In order to balance incentives for investment and socio-economic efficiency, the support level, i.e. in our case the fixed price premium, could be adjusted according to changes in wind park value and riskiness.

The attractiveness of offshore grids for different market actors depends heavily on the choice of regulatory regime, including market access, pricing rules and support. Certain constellations of regulatory regimes create barriers that may hamper the development of offshore grids due to diverging incentives. If meshed offshore grids are to be built due to their socio-economic benefits, the effects described in this study should be taken into consideration when making regulatory choices.

## Acknowledgement

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PAPER F

# A real options approach to analyse wind energy investments under different support schemes

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**Abstract**

*We adopt a real options approach to analyse investment decisions such as investment timing and capacity choice for offshore wind projects. By combining several uncertainty factors into a single stochastic process, we construct a model that provides closed-form solutions. We further introduce a capacity constraint and show its relevance for practical applications. Having created this general and easily applicable approach for analysing implications of different support policy instruments, we undertake a case study that quantifies differences in investment behaviour under feed-in tariffs, feed-in premiums and tradable green certificate schemes. We find that in most cases, green certificate schemes lead to later but larger investments due to the higher variance in profits experienced by investors. However, depending on the correlation between the uncertainty factors, the opposite may be the case. Policy makers can use our results to strategically design their renewable support schemes and develop tailor-made solutions to specific policy goals.*

**Keywords:** Real options; Offshore wind; Support instruments; Feed-in Tariffs; Green Certificates

## F.1 Introduction

Investments in renewable energy (RE) technologies accounted for more than 62% of global investments in power and fuel production assets in 2012 (UNEP/Bloomberg, 2013). The vast majority of these investments still relies on financial support from governments and the choice of support instrument can have significant impact on investment decisions. The scientific community continues to engage in an ongoing debate about which types of policy instruments are best suited to support RE (see e.g. del Río and Cerdá, 2014). In this paper, we contribute to this discussion by adopting a real options approach to analyse the impact of support instruments on investment behaviour. By taking the perspective of private investors, we aim to get a better understanding of their reaction to financial incentives set by policy makers, and thus, draw conclusions on the effects of different support schemes on project sizes and investment timing.

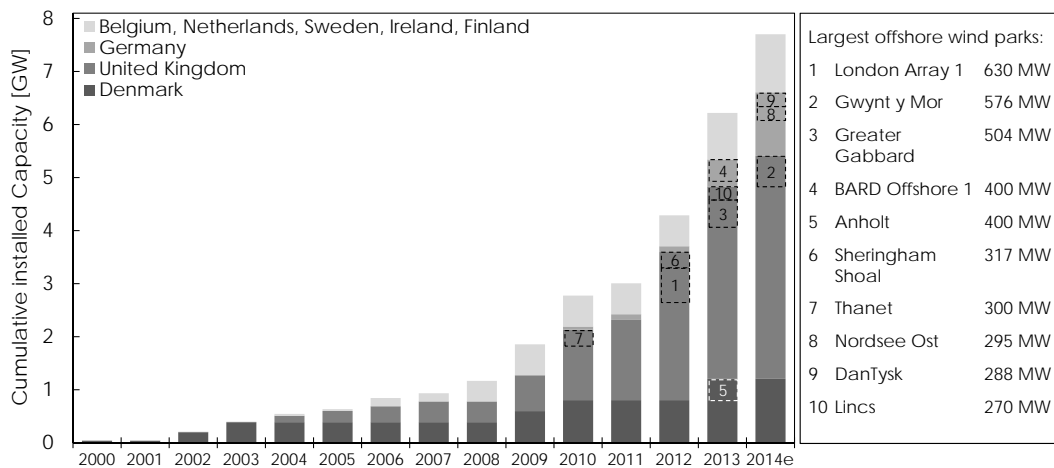
We adopt a real options approach because it inherently incorporates characteristics such as irreversibility of investment, uncertainty of the environment, and decision flexibilities in the investment appraisal. These characteristics are important, as in many market situations it can e.g. be optimal to postpone irreversible investments and likewise adapt the size of a project. For RE projects, this strategic dimension is especially significant, because up-front investment costs are typically very high in comparison to operational costs. Thus, the optimisation of the investment decision is crucial for the success of such projects.

We develop the model and then apply it to a specific case of offshore wind energy investment in the Baltic Sea, so that we can directly derive certain policy implications: We compare three different support schemes (feed-in tariffs, premiums, and green certificates) and reveal differences in investment behaviours under these schemes. Our model and the conclusions from our case study can be directly used by policy makers to optimise RE support scheme design.

The remainder of the paper is structured as follows. First, we give some background information on offshore wind investments (Section F.1.1). We then present our model in Section F.2 and derive some general conclusions on investment dynamics based on comparative statistics. In Section F.3, we apply the model to an offshore wind park in the Baltic Sea and derive concrete results for different support policies. Finally, we discuss our findings in Section F.4, including application options of the model and policy implications of the results. Section F.5 concludes with overall implications for policy makers and further research options.

### F.1.1 Research context: The economics of offshore wind investments in Europe

There are currently 45 offshore wind parks in Europe<sup>1</sup>. Figure F.1 shows their exponential development in the past. Offshore wind is also an important growth area for the future: In Europe, a growth from currently 8 GW to 44 GW is expected by 2020 (ECN, 2013). Global offshore wind investments could arrive at EUR 130bn annually in 2020, including EUR 14bn in Europe (Roland Berger, 2013).



**Figure F.1:** Offshore wind parks in Europe, based on data available from 4C (2013)

RE projects, as most investments, face numerous types of risks. Here, we focus

<sup>1</sup>commercial wind parks with a capacity of more than 10 MW

on economic risks, i.e. uncertainties that influence the gross margin of a project under ‘normal’ operation. Hence, political shocks (such as discontinuation of support scheme), social shocks (such as stakeholder opposition) or technical risks (such as changes in investment costs, or operational failures) shall not be part of this analysis. This way, we aim to create a transparent model that alone contains the elements relevant for the comparative analysis of different support schemes.

We focus on the three types of support instruments currently applied for offshore wind in Europe (see Kitzing et al., 2012): feed-in tariffs (FIT), feed-in premiums (FIP), and quota systems with tradable green certificates (TGC). We follow Kitzing et al. (2012) and Couture and Gagnon (2010) in their definitions: FIT schemes provide guaranteed prices and diminish the investors’ exposure to price variation. FIP are fixed add-ons to market prices and, hence, investors are exposed to market price changes. In TGC schemes, green certificates constitute additional income for investors next to sales on power markets. Both power and certificate prices are uncertain and traded. In 2011, nine European countries applied FIT, three countries applied FIP, and five countries applied TGC for the support of offshore wind (Kitzing et al., 2012).

## **F.2 Methods: Creating a real options model for investment decisions for wind energy projects**

### **F.2.1 Literature review**

Option-pricing theory was first applied to the valuation of assets by Black and Scholes (1973) and Merton (1973). Arrow and Fisher (1974) and Henry (1974) have contributed with seminal work on irreversible investments under uncertainty. Since then, a diverse field of real options analyses has developed, from commodity pricing over operational flexibility to investment decisions under uncertainty. Dixit and Pindyck (1994) give an excellent introduction to real options analysis.

While the real option approach was taken up in early studies of natural resources and their optimal exploitation (Arrow and Fisher, 1974; Tourinho, 1979), it was less relevant for power production assets during regulated times. Post de-regulation, however, Felder (1996) predicted an increase in the use of financial theory in the electricity sector. And indeed, the use of real option approaches in the area has been continuously increasing ever since.

Fernandes et al. (2011) give a comprehensive overview of related publications. The

studies most relevant to our work are: Venetsanos et al. (2002) who first applied real options to RE and more specifically to wind energy investments; Yu et al. (2006) who first assessed RE policy instruments using real options (for the case of Spain); Fleten et al. (2007) who optimised decentralised renewable power generation assets in terms of capacity choice and investment timing; and finally Boomsma et al. (2012) from whose approach we draw the most. Still, there are several differences between our approach and previous contributions:

First, we model the total gross margin (i.e. profit) of the project as a single stochastic process in contrast to modelling the underlying commodities<sup>2</sup>. This allows us to account for various sources of uncertainty while still being able to solve the model analytically (avoiding numerical approximation). We can thus introduce variation in wind resources, which has previously often been neglected. The approach also gives us greater flexibility to investigate indirect effects such as correlations between the underlying processes. Second, we introduce a capacity limit, i.e. a maximum project size. We find this necessary, as most investment projects face either restrictions on the available construction area or financial constraints. The capacity limit may also reflect a volume cap in a support scheme. Third, we do not consider uncertainty from the change of policy (i.e. possible discontinuation of support or switches to other support instruments). This can be seen as simplification as compared to Boomsma et al. (2012), but these effects are not in focus of our analysis.

### F.2.2 Model

We formulate our investment problem as a continuous-time real options problem, taking into account the flexibility of investment timing and capacity choice. In particular, investment timing can be viewed as an option on the value of an offshore wind project, for which capacity is optimally chosen. In modelling uncertainty, we assume that the operational gross margin per unit capacity of the investment project  $(\pi(t))_{t \geq 0}$  is governed by a geometric Brownian motion (GBM):

$$d\pi(t) = \mu\pi(t)dt + \sigma\pi(t)dz(t), \quad (\text{F.1})$$

where  $\pi(0) = \pi$  is the current margin,  $\mu$  and  $\sigma$  are the drift and volatility of the margin, respectively, and  $(dz(t))_{t \geq 0}$  is a standard Brownian motion (see nomenclature in Appendix F.A).

The operational gross margin is influenced by the electricity price  $S(t)$ , the production volume per capacity unit of the wind project  $\rho(t)$ , and support payments, all of which we combine in this single measure  $\pi(t)$ . The implications of assuming that  $\pi(t)$  is a GBM are discussed in Section F.2.3.1.

<sup>2</sup>This assumes that the gross margin follows a Markov process, which needs to be tested when applying the model to specific cases.



### F.2.2.1 Capacity choice

For given current margin  $\pi$  and capacity  $q$ , the value of the project  $V(\pi; q)$  is the expected total discounted operational gross margin over its lifetime less up-front investment costs. The capacity is chosen such as to maximise this project value:

$$\max_{0 \leq q \leq \bar{q}} \left\{ V(\pi; q) := \mathbb{E} \left[ \int_0^T e^{-rt} \Pi(\pi(t); q) dt - I(q) \middle| \pi(0) = \pi \right] \right\}, \quad (\text{F.2})$$

where  $\Pi(\pi; q)$  denotes the immediate operational gross margin of the project and  $I(q)$  denotes investment cost, both as a function of capacity  $q$ . Moreover,  $\bar{q}$  is the maximum capacity, such that  $q \leq \bar{q}$ . The capacity limit should be interpreted as a site-specific limit, and could reflect spacial constraints, legal limitations, or also budget constraints.

We assume that the discount rate  $r$  is constant with  $r > \mu$ . The discount rate should reflect the rate of return of other assets in the market with a similar exposure to risk. Under risk-neutral valuation, one may adjust the margin dynamics by the market price of risk such that  $r$  can be chosen as the risk-free rate of return. Here, however, we assume that the required rate of return on the project is exogenously specified.

We assume that the gross margin per unit capacity is not influenced by the project size, such that electricity prices and support payments are exogenous: This may for example be the case if production from the wind project is sufficiently small not to influence the market. Hence, we can assume the functional form  $\Pi(\pi; q) = \pi Q(q)$ , where the function  $Q(q)$  describes how production varies with capacity.

For a given capacity  $q$ , we obtain  $V(\pi; q)$  by simple integration, so that the value of the project is:

$$V(\pi; q) = \frac{1 - e^{-(r-\mu)T}}{r - \mu} \pi Q(q) - I(q) := \gamma \pi Q(q) - I(q), \quad (\text{F.3})$$

where  $\gamma = (1 - e^{-(r-\mu)T})/(r - \mu)$  is a compound factor that translates current into future revenues.

The first order conditions for the optimal capacity of the project are then

$$\gamma \pi \frac{dQ(q)}{dq} - \frac{dI(q)}{dq} \begin{cases} \leq 0, & \text{if } q = 0, \\ = 0, & \text{if } 0 < q < \bar{q}, \\ \geq 0, & \text{if } q = \bar{q}, \end{cases} \quad (\text{F.4})$$

i.e. for a positive capacity strictly below the maximum, the marginal value of the revenues equals the marginal costs of investment.

We assume that the production of the wind project is a concave and increasing function of capacity. Hence, production is increasing, but marginally decreasing with capacity, e.g. due to production losses such as from wake effects. The corresponding function is assumed to be:  $Q(q) = aq^b$ , with  $a > 0$  and  $0 < b < 1$ .

Moreover, we assume that investment cost of the wind park is an affine and increasing function of capacity, i.e. investment costs consist of a variable and a fixed cost element such that  $I(q) = Aq + B$ , with  $A, B > 0$ . The constant  $B$  describes the fixed investment costs which apply regardless of the project size, e.g. basic vessel rates, transformer cost, and cable layout cost. The constant  $A$  reflects the size-dependent investment costs, which increases with capacity, e.g. cost of turbines and foundations.

With the above specifications, the project value is a concave function of capacity. Therefore, the unconstrained optimal capacity choice is unique and can be found by using the first order conditions:

$$\tilde{q}(\pi) = \left( \frac{\gamma \pi a b}{A} \right)^{\frac{1}{1-b}}, \quad (\text{F.5})$$

with  $\tilde{q}(\pi) > 0$ .

If capacity  $\tilde{q}(\pi)$  exceeds the limit, it is optimal to invest the maximum available capacity  $\bar{q}$ . The optimal constrained choice of capacity is therefore:

$$q^*(\pi) = \min\{\tilde{q}(\pi), \bar{q}\} = \begin{cases} \left( \frac{\gamma \pi a b}{A} \right)^{\frac{1}{1-b}}, & \tilde{q}(\pi) < \bar{q}, \\ \bar{q}, & \tilde{q}(\pi) \geq \bar{q}. \end{cases} \quad (\text{F.6})$$

Note that  $\tilde{q}(\pi)$  depends on the value of the margin  $\pi(t)$  at the time of investment, and so does  $q^*(\pi)$ .

The corresponding value of the project is

$$V(\pi; q^*(\pi)) = \begin{cases} \frac{A(1-b)}{b} \left( \frac{\gamma \pi a b}{A} \right)^{\frac{1}{1-b}} - B, & \tilde{q}(\pi) \leq \bar{q}, \\ \gamma \pi a \bar{q}^b - A \bar{q} - B, & \tilde{q}(\pi) > \bar{q}. \end{cases} \quad (\text{F.7})$$

Below  $\bar{q}$ , the concave power production function leads to a value function which is convex in the per unit margin. Above  $\bar{q}$ , the value function is linear (see Figure F.2). Note also that  $V(\pi; q^*(\pi))$  is differentiable in  $\pi$  (left and right derivatives exist and are equal).

### F.2.2.2 Investment timing

We assume that the option to initiate the investment can be exercised at any time (i.e. it resembles an American option) and that the investment is fully irreversible, so that once the option is exercised the investment costs become sunk. At time  $t$ , we compare the value of the project when investing immediately with the value of waiting to invest at a later time (continuation value). Depending on whichever value is larger, we either invest or continue to wait. Since  $\pi(t)$  is a time-homogenous Markov process, the corresponding Bellman equation is

$$W(\pi) = \max \left\{ \max_{0 \leq q \leq \bar{q}} \{V(\pi; q)\}, \frac{1}{1 + rdt} \mathbb{E}[W(\pi + d\pi)|\pi] \right\}. \quad (\text{F.8})$$

In the continuation region, i.e. when it is optimal to wait, we apply Itô's Lemma (Itô, 1951), and arrive at the following ODE:

$$\frac{1}{2} \sigma^2 \pi^2 \frac{\partial^2 W}{\partial \pi^2} + \mu \pi \frac{\partial W}{\partial \pi} - rW = 0. \quad (\text{F.9})$$

The general solution to this ODE is (see Dixit and Pindyck, 1994):

$$W(\pi) = C_1 \pi^{\beta_1} + C_2 \pi^{\beta_2}, \quad (\text{F.10})$$

where  $\beta_1$  and  $\beta_2$  are the two roots of the quadratic equation:

$$K(\beta) = \frac{1}{2} \sigma^2 \beta(\beta - 1) + \mu\beta - r = 0. \quad (\text{F.11})$$

Since we have that the discount rate is positive, i.e.  $r > 0$ , we obtain  $K(0) = -r < 0$ . Also, since  $\mu < r$ , we have that  $K(1) = \mu - r < 0$ . Knowing that  $K(\beta)$  is a parabola with a positive coefficient in front of the second order term, we conclude that one root must lie to the left of zero (i.e. be negative) and one root must lie to the right of 1. We define  $\beta_1 > 1$  and  $\beta_2 < 0$  (see also Dixit and Pindyck, 1994).

In order to find the threshold level  $\pi^*$  that triggers investment, we can argue for three boundary conditions (all of which are described in more detail in Dixit and Pindyck, 1994). First, if  $\pi$  tends to zero, it remains at zero due to the characteristics of the GBM. Investment would never be optimal, and the option would be worthless, i.e.  $W(0) = 0$  (First value matching condition). From this condition, we can derive that  $C_2 = 0$ , as otherwise the second term of Equation (F.10) would drift to infinity. Therefore, we can simplify to:

$$W(\pi) = C_1 \pi^{\beta_1} := C \pi^{\beta}. \quad (\text{F.12})$$

Second, at the threshold level  $\pi^*$ , we are indifferent to waiting or investing immediately. Thus, the continuation value matches the value of immediate investment:  $W(\pi^*) = V(\pi^*; q^*(\pi^*))$  (Second value matching condition). Using Equations (F.7) and (F.12), we obtain:

$$W(\pi^*) = C\pi^{*\beta} = \begin{cases} \frac{A(1-b)}{b} \left( \frac{\gamma\pi^{*ab}}{A} \right)^{\frac{1}{1-b}} - B, & \tilde{q}(\pi^*) \leq \bar{q}, \\ \gamma\pi^{*a}\bar{q}^b - A\bar{q} - B, & \tilde{q}(\pi^*) > \bar{q}. \end{cases} \quad (\text{F.13})$$

We could now solve Equation (F.13) for  $\pi^*$  and derive the analytical solution for the investment threshold. However, the constant  $C$  is still unknown. We thus need a third boundary condition. Dixit (1993) shows that at the investment threshold  $\pi^*$ , the values of  $V(\pi^*; q^*(\pi^*))$  and  $W(\pi^*)$  should meet tangentially. Thus, both functions have the same slope (Smooth pasting condition):

$$\frac{dW}{d\pi}(\pi^*) = \frac{dV}{d\pi}(\pi^*; q^*(\pi^*)), \quad (\text{F.14})$$

Using again Equations (F.7) and (F.12), we arrive at:

$$\frac{dW}{d\pi}(\pi^*) = C\beta\pi^{*\beta-1} = \begin{cases} \gamma a \left( \frac{\gamma\pi^{*ab}}{A} \right)^{\frac{b}{1-b}}, & \tilde{q}(\pi^*) < \bar{q}, \\ \gamma a \bar{q}^b, & \tilde{q}(\pi^*) \geq \bar{q}. \end{cases} \quad (\text{F.15})$$

Now, when solving Equations (F.15) and (F.13) for  $\pi^*$ , we can derive the investment threshold for the capacity constrained investment:

$$\pi^* = \begin{cases} \frac{A}{\gamma ab} \left( \frac{Bb\beta}{A(\beta(1-b)-1)} \right)^{1-b}, & \tilde{q}(\pi^*) < \bar{q}, \\ \frac{1}{\gamma a \bar{q}^b} (A\bar{q} + B) \frac{\beta}{\beta-1}, & \tilde{q}(\pi^*) \geq \bar{q}. \end{cases} \quad (\text{F.16})$$

Hence, an investor with an investment option shall observe  $\pi(t)$  in the market. As soon as  $\pi(t)$  reaches the threshold  $\pi^*$ , the investment shall be undertaken. Note that  $\pi^* > 0$  for  $\tilde{q}(\pi^*) \geq \bar{q}$ , and  $\tilde{q}(\pi^*) < \bar{q}$  likewise implies  $\pi^* > 0$ .

For completeness we also determine the constant  $C$ :

$$C = \begin{cases} \left( \frac{B}{\beta(1-b)-1} \right) (\pi^*)^{-\beta}, & \tilde{q}(\pi^*) < \bar{q}, \\ (A\bar{q} + B) \frac{1}{\beta-1} (\pi^*)^{-\beta}, & \tilde{q}(\pi^*) \geq \bar{q}. \end{cases} \quad (\text{F.17})$$

Finally, to obtain the optimal capacity, we insert Equation (F.16) into Equation (F.5) and find the solution for  $\tilde{q}$  at  $\pi^*$ :

$$\tilde{q}(\pi^*) = \frac{\beta B b}{A(\beta(1-b)-1)}. \quad (\text{F.18})$$

Making use of the relationship  $q^*(\pi) = \min\{\tilde{q}(\pi), \bar{q}\}$ , we can summarise the results in the following proposition:

**PROPOSITION F.1**

*F.1.1 Assume that  $\bar{q}A(\beta(1-b)-1) - Bb\beta > 0$ . Then, there exists a threshold*

$$\pi^* = \frac{A}{\gamma ab} \left( \frac{Bb\beta}{A(\beta(1-b)-1)} \right)^{1-b},$$

*such that investment is optimal for  $\pi \geq \pi^*$ . At investment, the optimal capacity is*

$$q^*(\pi^*) = \frac{Bb\beta}{A(\beta(1-b)-1)}.$$

*F.1.2 Assume that  $\bar{q}A(\beta(1-b)-1) - Bb\beta \leq 0$ . Then, there exists a threshold*

$$\pi^* = \frac{1}{\gamma a \bar{q}^b} (A\bar{q} + B) \frac{\beta}{\beta - 1},$$

*such that investment is optimal for  $\pi \geq \pi^*$ . At investment the optimal capacity is*

$$q^*(\pi^*) = \bar{q}.$$

Thus, we have shown that the capacity constrained investment problem can be solved analytically. Having established this model, we proceed to derive some general conclusions based on comparative statistics, and then apply the model to a specific case. Both steps improve our understanding of the dynamics of investment behaviour and help us to draw conclusions for policy making.

### F.2.3 Discussion of the model and its implications

#### F.2.3.1 Assuming a geometric Brownian motion for the operational gross margin

We assume that the operational gross margin  $\pi(t)$  follows a GBM, combining different stochastic processes. This may be justifiable for certain situations. We consider operational costs for offshore wind parks negligible for this analysis. Thus,

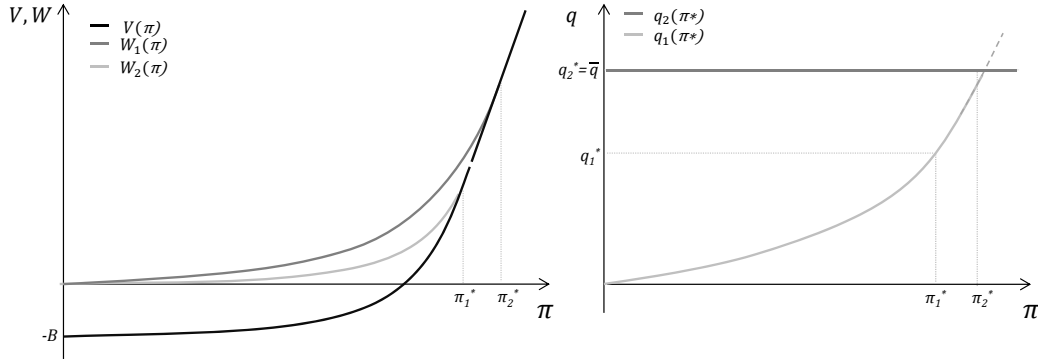
the gross margin  $\pi(t)$  is strictly positive. Moreover, if the two underlying processes of electricity prices  $S(t)$  and wind power production  $\rho(t)$  are GBMs, their product  $\pi(t) = S(t)\rho(t)$  is likewise a GBM (Dixit and Pindyck, 1994). Considering support payments, though, can raise issues. For FIT schemes,  $\rho(t)$  is multiplied with a constant price. With the above assumptions, the resulting gross margin continues to follow a GBM. For FIP schemes, however, a constant is added to  $S(t)$ , and the margin no longer follows a GBM. Moreover, for TGC schemes a stochastic support element is added to the electricity price, which would likewise lead to a change in the overall stochastic characteristics. As a first approximation, however, we can continue to operate with a GBM.

Early works involving commodity prices often assume such a rather simplistic approach to modelling of commodity prices (e.g. Brennan and Schwartz, 1985; Smith and McCardle, 1998), which produces transparent closed-form solutions. More recently, however, research tends to focus more on complexity of price process modelling (e.g. Thompson et al., 2004; Schwartz and Smith, 2000; Lucia and Schwartz, 2002). With our approach of modelling the combined gross margin, we strive to find a compromise between a realistic representation on the one hand and transparent results on the other. We emphasise that when applying our model to a concrete case, the stochastic characteristics of the gross margin should always be tested for following a GBM and the applicability of our model should be assessed.

### F.2.3.2 The importance of a capacity constraint

Figure F.2 illustrates the value functions after investment  $V(\pi; q^*(\pi))$  and before investment  $W(\pi)$  for the case of Proposition F.1.1, where the invested capacity is below the maximum, and for Proposition F.1.2, where the invested capacity is at the maximum. For  $\pi$  such that  $q^*(\pi) < \bar{q}$ , invested capacity  $q^*(\pi)$  and project value  $V(\pi; q^*(\pi))$  are both increasing and convex in  $\pi$ . For  $\pi$  such that  $q^*(\pi) = \bar{q}$ ,  $V(\pi; q^*(\pi))$  is linearly increasing in  $\pi$ , whereas  $q^*(\pi)$  is constant. Furthermore,  $W(\pi)$  is increasing and convex in  $\pi$ . For Proposition F.1.1, we denote the value function before investment by  $W_1(\pi)$ , and for Proposition F.1.2 by  $W_2(\pi)$ . Moreover, for Proposition F.1.1, we denote the threshold by  $\pi_1^*$  and the optimal capacity by  $q_1^*(\pi_1^*) < \bar{q}$ , and for Proposition F.1.2 by  $\pi_2^*$  and  $q_2^*(\pi_2^*) = \bar{q}$ . Thus, under normal conditions, the invested capacity under Proposition F.1.1 is lower than under Proposition F.1.2 ( $q_1^*(\pi_1^*) < \bar{q}$ ). As illustrated in Figure F.2, Proposition F.1.1 also leads to a lower investment threshold than Proposition F.1.2, i.e.  $\pi_1^* < \pi_2^*$ .

To analyse the effect of introducing a capacity limit, we consider the potential case of Proposition F.1.1 without the assumption  $\bar{q}A(\beta(1-b)-1) - Bb\beta > 0$ , i.e. without a capacity limit, and compare it to the case of Proposition F.1.2. Now, it may happen



**Figure F.2:** Illustration of project value, option value, and relationship between investment threshold and invested capacity for two cases of Proposition F.1.

that  $\pi_1^* > \pi_2^*$  if and only if

$$\frac{A}{b} \left( \frac{Bb\beta}{A(\beta(1-b)-1)} \right)^{1-b} > \frac{1}{\bar{q}^b} (A\bar{q} + B) \frac{\beta}{\beta-1}. \quad (\text{F.19})$$

With realistic ranges of input parameters of  $0.5 < b < 0.9$ ,  $1 < \beta < 15$ ,  $100 < \bar{q} < 400$ , and  $A, B$  in the range of several mEUR, Equation (F.19) holds true in almost all application cases. This implies that a model without a capacity limit would almost always result in a higher investment threshold. Thus, neglecting the capacity constraint would lure investors into investing later than optimally.

### F.2.3.3 Parameters of the gross margin process

The effect of the input parameters  $\mu$  and  $\sigma$  on the stochastic gross margin process are best analysed by looking at  $\beta$ , which is found by solving Equation (F.11):

$$\beta = \frac{\sigma^2 - 2\mu + \sqrt{8r\sigma^2 + (\sigma^2 - 2\mu)^2}}{2\sigma^2}. \quad (\text{F.20})$$

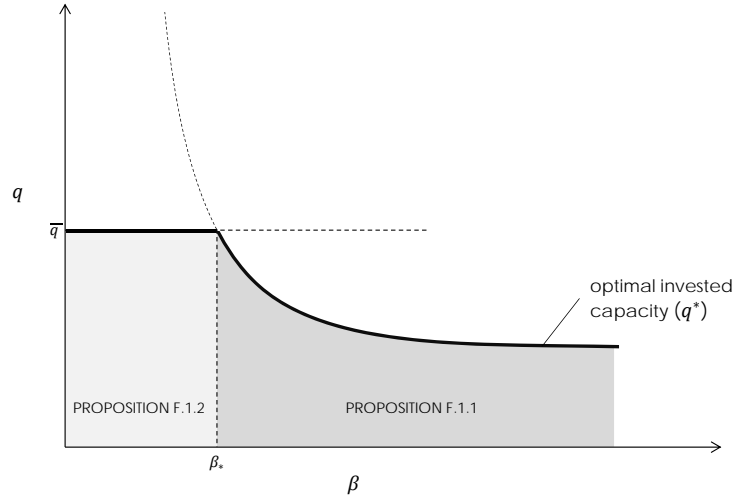
Note that  $\beta$  is decreasing in  $\mu$  and  $\sigma$  and increasing in  $r$ .

It is useful to analyse the outcomes from this perspective, because the deterministic input factors  $(A, B, b, \bar{q})$  are often project-specific and given, whereas the stochastic input parameters mostly depend on the location and market. Thus, the following serves as an analysis of a given project under different market conditions. We first

observe that Proposition F.1.1 applies if  $\beta > \beta_*$ , where the threshold  $\beta_*$  is determined by:

$$\beta_* = \frac{\bar{q}A}{\bar{q}A(1-b) - Bb}, \quad (\text{F.21})$$

High  $\beta$  could arise from a combination of low  $\sigma$  and  $\mu$  and high  $r$ . Proposition F.1.2 applies if  $\beta \leq \beta_*$ , provided the denominator is positive, and otherwise for all  $\beta \geq 0$ . We next observe that  $q^*(\pi^*)$  is decreasing in  $\beta$  for  $\beta > \beta_*$  and constant for  $\beta \leq \beta_*$ . Figure F.3 illustrates the relationship between  $\beta$  and the optimal invested capacity  $q^*(\pi^*)$ .



**Figure F.3:** Relationship between the optimal investment capacity  $q^*$  and  $\beta$ , for any given wind park characteristics of  $A, B, b$

Investigating the effects of changes in  $\sigma$ , we find that, since the investment capacity is decreasing in  $\beta$ , the lower  $\sigma$ , the lower the optimal capacity. When  $\sigma$  approaches zero,  $\beta$  approaches infinity, and the optimal capacity tends to its minimum level of  $Bb/A(1-b)$ . Since  $\pi^*$  is likewise decreasing in  $\beta$ , the same conclusions hold for the investment threshold.

#### F.2.3.4 Project characteristics

The wake parameter  $b$  is important for the investment decision. Within the investment range, we have that the higher  $b$ , the lower the investment threshold (*all other things equal*). Hence, in practice, a reduction of wake losses will lead to an earlier deployment. Such reduction can easily be achieved through an increase in the distance between turbines. However, with a limited construction area for the wind park, this will often come to the expense of a reduced overall capacity limit. We include a



sensitivity analysis in Section F.3.4.2 to investigate wake loss effects. Moreover, the topic could be interesting for more detailed analysis.

Investment decisions are likewise influenced by the relationship between the fixed part of the investment cost  $B$  and the marginal (capacity-depending) part  $A$ . The higher  $B$  is in relation to  $A$  (i.e. the higher degree of fixed cost a project has), the more likely it is that the capacity limit is reached. This reflects rational investment decision-making since a marginal increase in investment capacity becomes more likely the smaller the marginal cost per unit of additional capacity  $A$  is. A project developer who aims at optimising the project size could use this insight to strategically shift cost between  $A$  and  $B$ , e.g. through contract negotiations.

### F.3 Model application: A case study for offshore wind

We use a case study on an offshore wind park project in the Baltic Sea to test the practical implications of the model. As a practical example for the choice between support schemes, the wind park could have interconnection options to either Denmark (with a tendered FIT scheme) or Sweden (with a technology-neutral TGC scheme). Our model could be a helpful decision tool for the interconnection decision. The model also allows for more general comparisons between different support schemes, as discussed in Section F.4.

#### F.3.1 Sources of data and data description

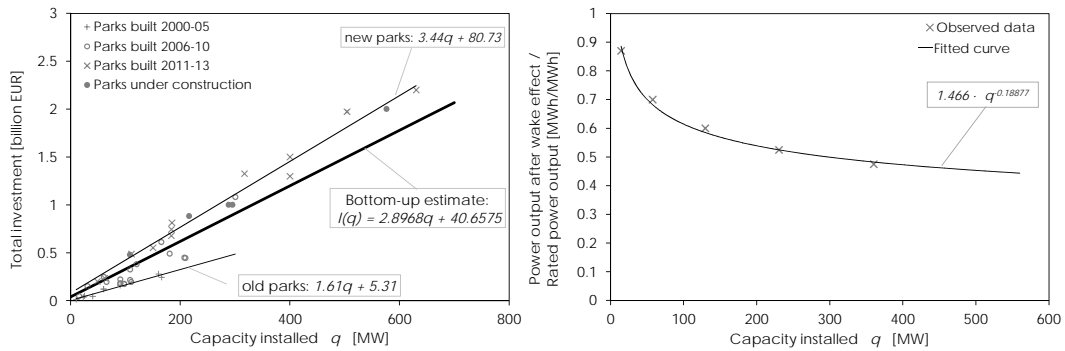
We assume to have an average offshore wind park in terms of layout and technology, using data from 4C (2013). The 45 existing commercial offshore wind parks in Europe have turbine sizes between 2 MW and 6.15 MW, and 48% of all installed turbines have a capacity of 3.6 MW. We use a 3.6 MW turbine with 90m hub height and 120m rotor diameter. The project lifetime is assumed to be 20 years. Furthermore, we estimate the risk-free rate based on the long-term interest rate statistics for EU Member States, which are secondary market yields of government bonds with a remaining maturity close to ten years (as published by ECB, 2013). Here, both Denmark and Sweden have an average annual rate of 3.6% (2001 to mid 2013).

### F.3.1.1 Investment cost and power production function

We estimate the investment cost function  $I(q) = Aq + B$  in a bottom-up process developed by Dicorato et al. (2011), with some minor modifications. All formulae and parameter estimations are described in more detail in Appendix F.B. In short, the investment costs are composed of equipment purchase and installation cost for wind turbines, foundations, electrical system, transmission infrastructure, and offshore substation, as well as project development cost. Most of these costs have a fixed element and a capacity-dependent element. The resulting investment cost function is estimated as (in mEUR):

$$I(q) = 2.8968q + 40.6575. \quad (\text{F.22})$$

Figure F.4 shows that the results of the bottom-up estimation are consistent with trends derived from empirical data for Europe (based on 4C, 2013).



**Figure F.4:** Estimated investment cost function based on Dicorato et al. (2011) and 4C (2013) (left), and estimated production losses due to wake effect based on González-Longatt et al. (2012) (right)

To estimate production function  $Q(q) = aq^b$ , we assume that  $a$  and  $b$  are determined by wake losses only. We use empirical data from González-Longatt et al. (2012), who provide a ‘wake coefficient’ for five different sizes of wind parks (between 4 and 100 turbines) and six different tower distances (between four and nine rotor diameters), calculated as the ratio between power output levels of a wind park excluding and including wake effects. Assuming turbines are placed at four rotor diameters distance from each other, we fit the function shown in Figure F.4 on the right hand side. We estimate the parameters  $a$  and  $b$  by multiplying the fitted function with the total production of the wind park for each level of capacity installed. The resulting profit function is estimated as:

$$Q(q) = 1.466q^{0.8112}. \quad (\text{F.23})$$

### F.3.1.2 Operational gross margin

As discussed, we assume that the operational gross margin  $\pi(t)$  is a function of electricity price  $S(t)$ , production volume  $\rho(t)$ , and support payments. The gross margin function  $\pi(t)$  for the three support schemes FIT, FIP and TGC is as follows:

$$\begin{aligned}\pi_{FIT}(t) &= \rho(t) \cdot FIT, \\ \pi_{FIP}(t) &= \rho(t) \cdot (S(t) + FIP), \\ \pi_{TGC}(t) &= \rho(t) \cdot (S(t) + TGC(t)).\end{aligned}\tag{F.24}$$

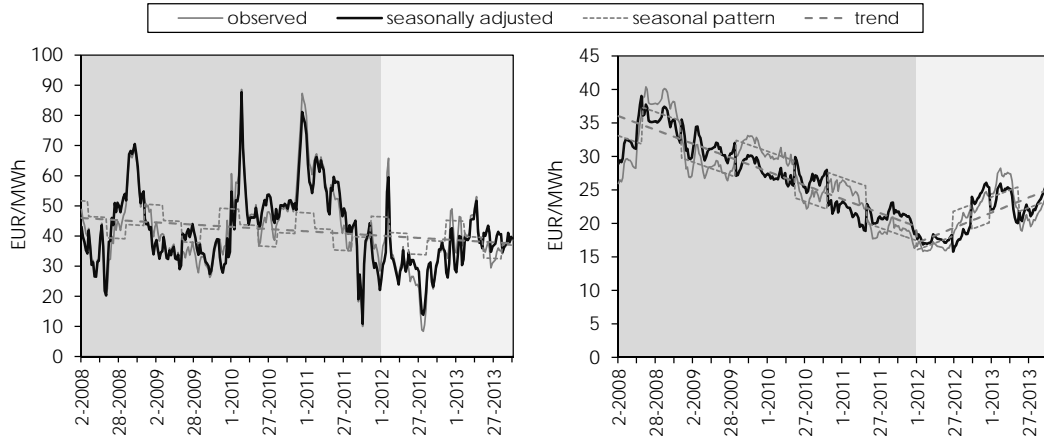
We derive the production volume  $\rho(t)$  from wind speed measurements (every 10 minutes) at the FINO 2 platform, an offshore wind site in the Baltic Sea. We convert wind speeds to power outputs by applying the approach of Norgaard and Holttinen (2004), using a typical power curve of a 3.6 MW turbine and a spatial dispersion of the wind park over 10 km<sup>2</sup>. For the power prices  $S(t)$ , we use day-ahead NordPool spot system prices on hourly basis (Energinet.dk, 2013). The time series  $TGC(t)$  is based on historical data of the Swedish certificate market on a weekly basis (SKM, 2013). We have a consistent data set for  $\rho(t)$ ,  $S(t)$  and  $TGC(t)$  from January 2008 to October 2013. Gaps in the data arise from failures in wind speed measurements, accounting for 3.6% of the data sample. We fill these gaps by linear interpolation.

We identify a structural change in power and certificate price developments in the beginning of 2012, when, amongst other changes, the Swedish certificate scheme was expanded to a joint market with Norway. We therefore undertake the analysis for two separate periods, 2008-2011 and 2012-2013, as illustrated in Figure F.5 by the shaded areas.

Time series analysis reveals certain seasonality in the data sets. Our model is however based on a non-seasonal GBM. We therefore remove the seasonal pattern (found by a least square linear regression) from all three time series (exemplarily shown for  $S(t)$  and  $TGC(t)$  in Figure F.5) and proceed to operate with seasonally adjusted values. This should be taken into account when interpreting the resulting profit threshold levels.

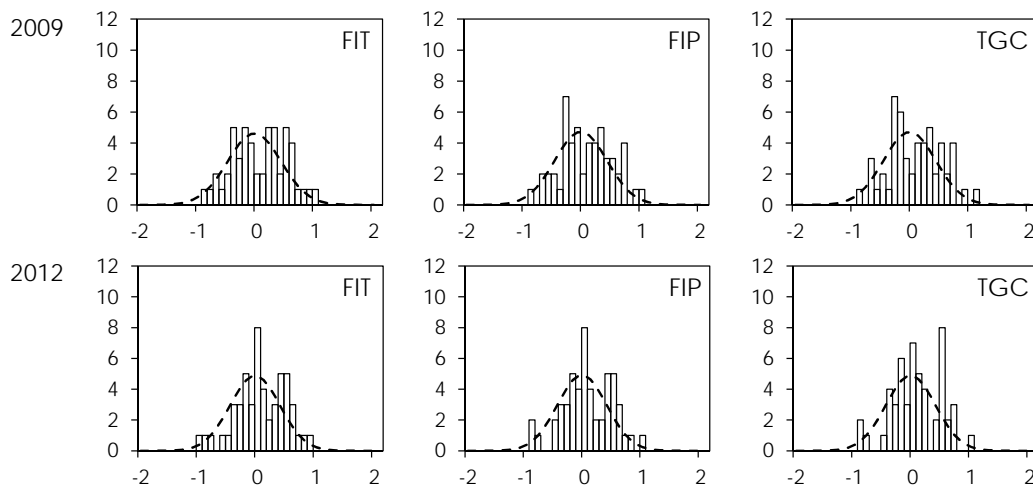
We compute the operational margins from  $\rho(t)$ ,  $S(t)$  and the support payments using Equation (F.24) on a weekly basis, corresponding to the time resolution of the underlying certificate prices. With  $TGC(t)$  being based on historical values, we set the levels for FIT and FIP so that the present value of the per unit margin during the relevant period is the same for all three options. This way, we ensure comparability of the results.

Since  $\pi(t)$  follows a GBM, we have that  $d\ln(\pi_t) = (\mu - \frac{1}{2}\sigma^2) dt + \sigma dz$ , with  $\mu$  and



**Figure F.5:** Power prices (weekly averages) and certificate prices, seasonally adjusted

$\sigma$  being the parameters we need to estimate<sup>3</sup>. We assume implicitly that  $d\ln(\pi_t)$  is normally distributed, and therefore test our time series for applicability. We apply the Kolmogorov-Smirnov test (see Corder and Foreman, 2009), in which we test the data for sufficient evidence to reject the  $H_0$  hypothesis of non-normal distribution. Unfortunately, for the years 2008, 2010, 2011 as well as for the period 2008-11, we cannot reject the hypothesis  $H_0$  with sufficient confidence ( $> 95\%$ ). Since we only have 40 observations in 2013, we do not use this year as a stand-alone case. Consequently, we operate only with the time series of the years 2009, 2012 and 2012-2013, for all of which the  $H_0$  hypothesis is rejected with  $> 99\%$  confidence. Figure F.6 shows the data fitted to a normal distribution for the years 2009 and 2012.



**Figure F.6:** Histograms of  $d\ln(\pi_t)$  for the best fitting data sets 2009 and 2012

Table F.1 shows the estimated parameters for the gross margins of FIT, FIP, and

<sup>3</sup>As described in Burger et al. (2007), we determine  $(\mu - \frac{1}{2}\sigma^2)$  and  $\sigma$  as the mean and standard deviation of  $(\ln(\pi_t) - \ln(\pi_{t-1}))$  in our time series. From this, we can derive  $\mu$ .

TGC.

**Table F.1:** Characteristics of the operational gross margins  $\pi$  for model input in the three base years

	2009			2012			2012-13		
	FIT	FIP	TGC	FIT	FIP	TGC	FIT	FIP	TGC
$\mu$	5.73	5.51	5.50	4.96	5.04	5.22	5.71	5.76	5.84
$\sigma$	3.29	3.22	3.23	3.06	3.04	3.05	3.36	3.35	3.37
$\beta$	6.25	6.51	6.51	7.21	7.10	6.86	6.27	6.22	6.13

Using  $\mu$  and  $\sigma$  as fixed parameters for our model implies that we do not expect stochastic characteristics to change over time. Hence, it is crucial to consider different time periods, as we do for 2009, 2012, and 2012-13. We implicitly assume that for each of the cases, the gross margin is expected to develop in the future as in the respective basis year.

Based on our observations discussed in Section F.2.3.3, we expect the case with the highest  $\beta$  to result in the lowest investment capacity and the lowest investment threshold. In 2009, the FIT scheme had the lowest  $\beta$ , whereas it is the opposite case for the more recent years. Hence, we expect diverging results.

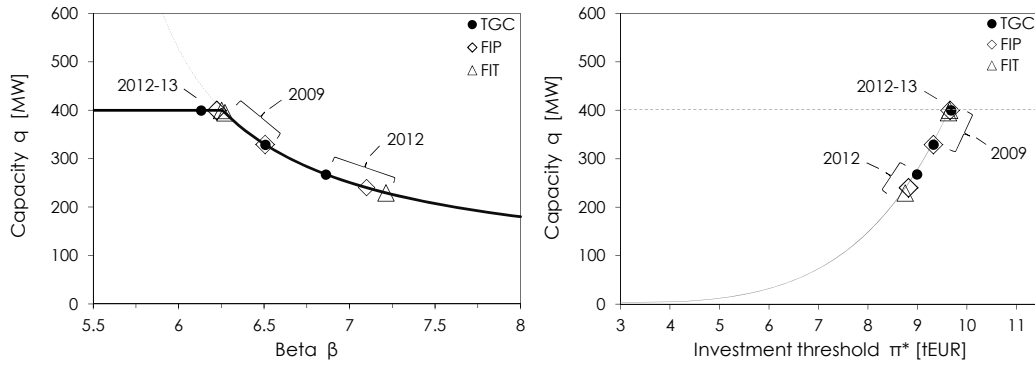
### F.3.2 Case results

By inserting all identified model parameters into the equations of Proposition 1, we arrive at the model results. Figure F.7 and Table F.2 show the resulting optimal invested capacities and investment thresholds for all three basis years. Table F.2 also presents the results for a model that does not incorporate the capacity constraint (unlimited capacity). The practical benefit of having introduced the capacity limit becomes apparent: The investment threshold lies up to 2% higher in the unconstrained model. This confirms our reasoning in Section F.2.3.2: by introducing the capacity limit, we prevent that investments are undertaken later than optimal.

**Table F.2:** Case results for the optimal capacity invested  $q^*$  (in MW) and for the annualised investment threshold  $\pi^*$  (in EUR per week)

		2009			2012			2012-13		
		FIT	FIP	TGC	FIT	FIP	TGC	FIT	FIP	TGC
unlimited capacity	$q^*$	402	329	329	230	240	268	395	413	452
	$\pi^*$	9,655	9,318	9,316	8,748	8,817	8,985	9,625	9,701	9,860
capacity constraint	$q^*$	400	329	329	230	240	268	395	400	400
	$\pi^*$	9,647	9,318	9,316	8,748	8,817	8,985	9,625	9,654	9,674

In the capacity constrained model, the results are also according to our expectation: For basis year 2009, the FIT returns the highest investment threshold and invested



**Figure F.7:** Case results for invested capacity  $q$  in relation to stochastic characteristics expressed by  $\beta$  and the investment threshold  $\pi^*$ , in the capacity constrained case

capacity (at the limit of 400 MW), whereas invested capacities under the FIP and the TGC lie significantly lower (71 MW less). For years 2012 and 2012-13, the FIT results in the lowest investment threshold and invested capacity (for 2012, 38 MW less invested capacity than under the TGC).

Overall, we experience significant differences between FIT, FIP, and TGC, which can be up to 17-18% in terms of invested capacity (329 to 400 MW in 2009 and 230 to 268 MW in 2012), and up to 3-4% in terms of investment threshold (9,316 to 9,647 EUR/week in 2009 and 8,748 to 8,985 EUR/week in 2012). As expected, there is ambiguity about which support scheme triggers the lowest and highest investment thresholds.

### F.3.3 Analysis of results

#### F.3.3.1 Why do the results diverge for the different basis years?

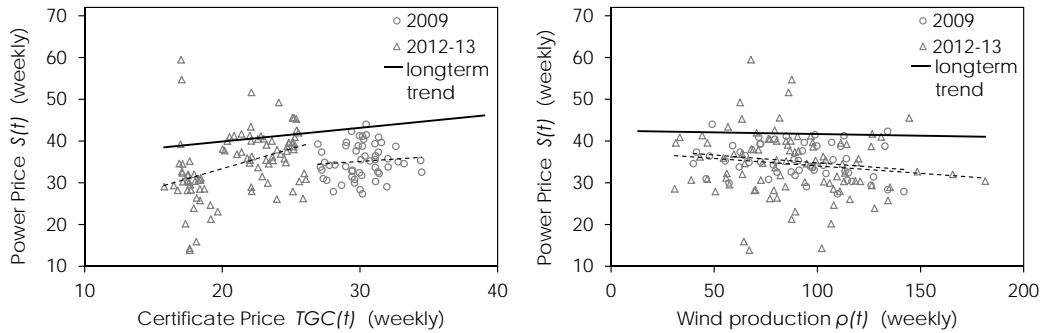
As described above, the three basis years 2009, 2012 and 2012-13 lead to diverging results when comparing FIT, FIP and TGC schemes. This can be explained by the input time series: In 2009, the TGC and FIP time series have a higher  $\beta$  than the FIT series. Hence, the FIT leads to higher investment threshold and invested capacity. The opposite is the case in the more recent data from 2012 and 2012-13, where the FIT time series has the highest  $\beta$ .

The reason for the diverging levels of  $\beta$  are differences in trend (drift), variation (volatility) and correlation of the underlying stochastic elements. The most important factors are 1) trend of power prices  $S(t)$  and certificate prices  $TGC(t)$ , 2)

correlation of power prices  $S(t)$  and wind production  $\rho(t)$ , and 3) level and variability of certificate prices  $TGC(t)$  in relation to power prices  $S(t)$ , as well as the correlation of the two. The level of certificate price matters, as it changes the relative importance of the stochastic characteristics between  $TGC(t)$  and  $S(t)$ .

Whereas  $\pi_{FIT}(t)$  is only subject to variation and trend of  $\rho(t)$ , the other two time series are exposed to variation and trend of a combination of  $S(t)$  and  $\rho(t)$ . Thus, a negative correlation of  $\rho(t)$  and  $S(t)$  and similar trends may reduce the variation of  $\pi_{TGC}(t)$  and  $\pi_{FIP}(t)$  as compared to  $\pi_{FIT}(t)$ , and vice versa.

In 2009, certificate prices were on a stable high level and had no significant correlation to the power prices ( $< 0.097$ ) (see Figure F.8 on the left), so FIP and TGC results are very similar. Both are influenced by the negative trend of  $S(t)$  and a strong negative correlation of  $\rho(t)$  and  $S(t)$  ( $-0.24$ ) (see Figure F.8 on the right). Thus, the FIT scheme resulted in the lowest  $\beta$  and highest investment threshold. In 2012,  $S(t)$  began to have a positive trend, affecting both  $\pi_{FIP}(t)$  and  $\pi_{TGC}(t)$ , and there occurred no significant correlation of  $S(t)$  and  $\rho(t)$  ( $-0.04$ ), so that  $\pi_{FIP}(t)$  and  $\pi_{TGC}(t)$  had a comparatively higher variability (with a small difference). The  $TGC(t)$  time series switched to a positive trend (see Figure F.5) and started to be positively correlated with  $S(t)$  ( $0.14$ ), affecting both trend and variation of  $\pi_{TGC}(t)$ , so that the TGC results now had the lowest  $\beta$  and highest investment threshold. In 2012-13, a stronger negative correlation of  $S(t)$  and  $\rho(t)$  occurred again, though to a lesser extend ( $-0.14$ ). However, this was more than compensated by the changed characteristics of certificate prices  $TGC(t)$ , which showed higher variation and higher correlation to  $S(t)$  ( $> 0.38$ ). Thus also in 2012-13, the TGC had the highest investment threshold.



**Figure F.8:** Correlations of power price  $S(t)$  and certificate price  $TGC(t)$ , as well as power price  $S(t)$  and wind production  $\rho(t)$

From a rough analysis of the long term trends (2008-2013), the two time series  $S(t)$  and  $TGC(t)$  have shown a tendency to be positively correlated, whereas  $S(t)$  and  $\rho(t)$  have had no significant correlation in the past (see Figure F.8). Year 2012 fits best to this pattern (with correlations of  $0.14$  and  $-0.04$ ). In the years 2012-13, the negative correlation of  $S(t)$  and  $\rho(t)$  ( $-0.14$ ) is offset by a strong positive correlation of  $S(t)$

and  $TGC(t)$  (0.38). This gives us reason to put more weight on the results from years 2012 and 2012-13. Note that we are not trying to forecast likely correlations in the future. Some might argue that there is evidence for increasing negative correlations of  $S(t)$  and  $\rho(t)$  in systems with very high wind penetration. This is however not yet the case for the NordPool system as a whole.

### F.3.3.2 Which country would the wind park investor prefer to connect to?

We mentioned before that our model can help with interconnection decisions, if an investor has the option to connect to more than one country. In general, we find that investment would first be triggered in the country with the lowest investment threshold. We find this to be (*all other things equal*) the system with the highest  $\beta$ , corresponding to the lowest variation of gross margin (and thus highest income stability).

Concretely, we can give a conditional answer for an average offshore wind park in the Baltic Sea: When relying on the long term trend (years 2008-2013) in regards to stochastic characteristics, our wind park would have chosen to connect to Denmark first, as it is the country that provides the FIT scheme. However, if the investor expected that correlations of the three underlying processes deviate from the long-term trend and that the future is more similar to e.g. the year 2009, he could also have preferred the TGC scheme in Sweden.

## F.3.4 Sensitivity analysis

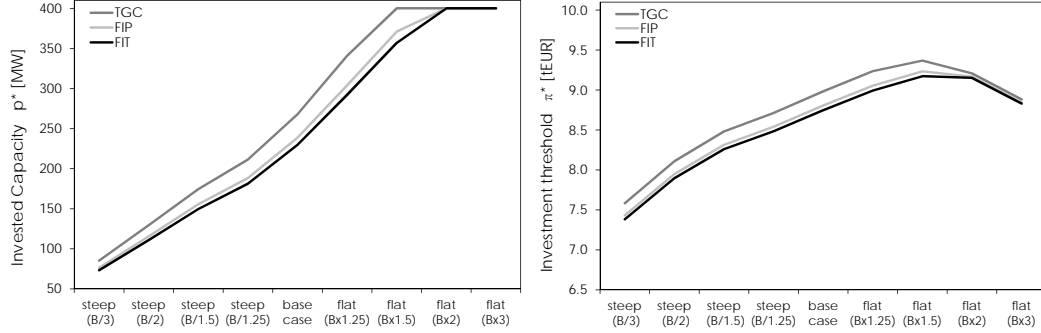
We scrutinise our case results for sensitivity to several significant input factors, namely investment cost, wake effect, variation in wind production, and certificate prices. For simplicity, we only show results for year 2012. The conclusions from years 2009 and 2012-13 are similar.

### F.3.4.1 Sensitivity analysis on the investment cost function

Assuming that the average total investment cost for a medium sized park should remain constant, we test the sensitivity of results to the relation between  $A$  and  $B$ . Results are shown in Figure F.9 for the effect on invested capacity and investment threshold for different slopes of the investment cost function (from very steep (small



$B$ ) to very flat (large  $B$ )).



**Figure F.9:** Sensitivity results for the investment cost function (results for year 2012)

Below the capacity limit, we observe that, the lower the slope of the investment cost function (the larger  $B$  is in relation to  $A$ ), the higher the invested capacity and also the higher the investment threshold. This confirms our general conclusion from Section F.2.3.4. The changes are similar for all support schemes. When the capacity limit is reached, the investment threshold decreases with a decreasing slope of the investment cost function, so that a reduction of  $B$  leads to earlier investment.

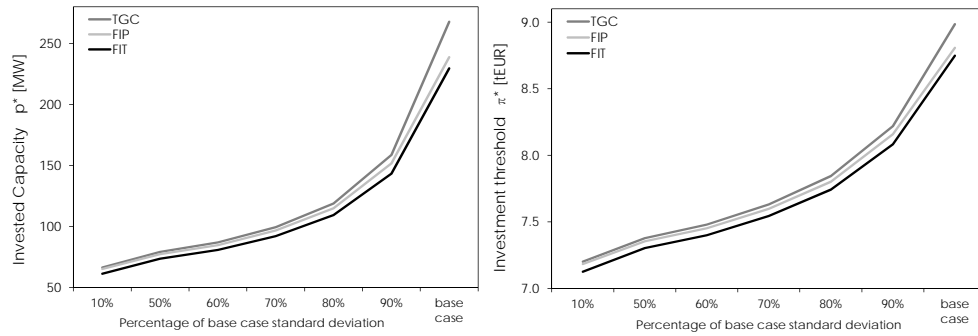
#### F.3.4.2 Sensitivity analysis on the power production function (wake effect)

As discussed in Section F.2.3.4, reducing wake losses can improve the business case of a wind park and would lead to higher invested capacities. Using Equation (F.18), we find that already a moderate increase of the wake loss parameter  $b$  would lead to significant increases of invested capacity. In the base case,  $b = 0.8112$  leads to an invested capacity of 230 MW for the FIT. An increase to  $b = 0.8321$  would be sufficient to trigger investment at the capacity limit of 400 MW. The respective levels for FIP and TGC are  $b = 0.8299$  and  $b = 0.8252$ . Such moderate increases of  $b$  could be achieved by increasing the turbine distances by 0.25 rotor diameters.

#### F.3.4.3 Sensitivity analysis on the stochastic gross margin

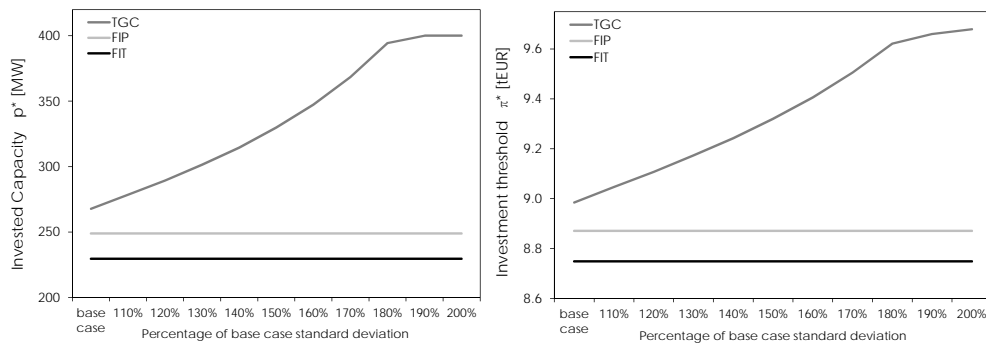
The variation of wind production is very high compared to that of power and certificate prices, even on a weekly basis. It dominates the gross margin in the base case. Hence, we analyse the impact of reduced wind variation. By keeping the average production constant, we reduce the divergence of the hourly production values from the average by a certain factor and so achieve a lower standard deviation (e.g. 50% of the original standard deviation) as shown in Figure F.10. We find that reduced

variation of wind reduces the invested capacity and the investment threshold significantly. The effect is similar for all schemes, so the comparative conclusions remain valid.



**Figure F.10:** Sensitivity results for wind production (standard deviation is reduced with  $x\%$  as compared to base case standard deviation (results for year 2012)

The variation of certificate prices is low compared to the power prices. Therefore, we analyse an increase in their variation up to a level similar to the power prices (ca. 200% of the original standard deviation). Such change only influences results for the TGC scheme. Here, both invested capacity and investment threshold increase, as shown in Figure F.11. Consequently, the higher the variation of certificate prices, the later investments will occur under TGC as compared to FIT and FIP. As this conclusion also depends on the correlation of power and certificate prices, it should be re-evaluated when considering different stochastic characteristics.



**Figure F.11:** Sensitivity results for certificate prices (standard deviation is increased to  $x\%$  as compared to base case standard deviation (results for year 2012)

## F.4 Discussion

### F.4.1 Application options of the model

Our model is based on the combined gross margin of a project. This approach differs from most other studies using observable commodity prices. Doing this, we can handle several sources of uncertainty and reflect some of the complexity of real-life problems while still being able to arrive at closed-form solutions. However, we acknowledge that this approach also comes with some significant restrictions, as discussed in Section F.2.3.1. For instance, it is not possible to include mean-reversion or spikes into one of the processes without compromising the overall GBM characteristic. Since we use the same model structure for all support schemes, we can, despite the restrictions, draw general conclusions about comparative investment incentives. To address some of the drawbacks of this approach, further development could include expanding the model to accommodate seasonality and mean-reversion. It is, however, not certain that increased complexity would lead to different conclusions. E.g. Lo and Wang (1995) show that GBM and mean-reversion models do not produce significantly different results in long-term problems.

### F.4.2 Policy conclusions from case results in the context of other studies

Mitchell et al. (2006), Butler and Neuhoff (2008), and Klessmann et al. (2008) have shown qualitatively that FIT schemes can be more effective in stimulating RE investments by creating a low-risk environment for investors. Boomsma et al. (2012) have confirmed this quantitatively.

Our results are more differentiated. We can confirm that the support scheme which creates the low-risk environment (i.e. lowest variation in profits) leads to the lowest investment thresholds and, thus, earliest investment. This equals faster deployment at the same support level and corresponds to the results of the above mentioned studies. However, our cases show that not necessarily the FIT scheme provides the low-risk environment: with certain correlations of power prices, certificate prices, and wind production, a TGC scheme can also lead to the lowest variations in profits (see the Nordic market in 2009).

In the long term (2008-2013), power and certificate prices have been positively correlated on the Nordic market and there has been no significant correlation of wind production and power prices. Hence, in general we expect the TGC to lead to a higher variance in profits than FIT or FIP. However, it would be necessary to inves-

tigate systematic correlations of the underlying stochastic processes and their future developments in more detail. This lies beyond the scope of this paper.

#### F.4.3 Discussion of implications for policy makers

Policy design, and especially the determination of support levels in FIT and FIP schemes, is often based on cost-benefit analysis. However, to design effective and efficient policies, policy makers must look beyond costs and consider all aspects of concern for private investors (Gross et al., 2010). Of particular relevance for RE projects is exposure to risk, strategic flexibilities and real options. If not adequately reflected in the design of support schemes, investors might react differently to incentives than intended. It is, thus, of utmost importance for policy makers to have access to an evaluation framework that takes strategic flexibilities and uncertainties into account. Our model provides an easily applicable framework for comparative analyses of different support schemes.

Concretely, we have analysed policy implications of three support schemes (FIT, FIP, and TGC) for an offshore wind park in the Baltic Sea. A pure cost-benefit analysis would determine the support level using a cost-based estimation, e.g. the levelised cost of electricity, which would be the same for all three support schemes.

However, by considering real options, we find that the wind park under a TGC scheme requires an up to 3% higher profit margin than under a FIT (in the 2012 case) for triggering investment. Also, depending on the correlation between the underlying stochastic factors, the opposite may be the case and the TGC scheme might require lower profit margins for investment. Until now, however, this has only occurred in an exceptional single year (2009).

Two concrete policy implications can be derived: First, TGC, FIP and FIT schemes providing the same current profit margin (i.e. the same equivalent support level) do not provide the same investment incentive. The scheme which causes the highest variation in profits has the highest investment thresholds and, thus, leads to the slowest deployment. Second, this first effect could be mitigated by policy makers through an increase in support levels (FIT and FIP). In a TGC, the effect may lead to increases in certificate prices if offshore wind is the marginal technology. In any case, overall support costs will become higher.

Another related effect is that low market uncertainties and a lower investment threshold can lead to smaller project sizes, in our calculation up to 17% in the FIT scheme (2012 case). When dealing with large bulk investments, as offshore wind parks generally are, this effect might not be desired in light of overall deployment targets.

The implications of our approach are not restricted to investment behaviour for a single wind park. The analysis can easily be broadened into a larger scope, e.g. to investigate support schemes with a volume cap represented by our capacity constraint. This has special relevance in competitive auction or tender processes, which are increasingly popular for offshore wind in Europe (Kitzing et al., 2012). With the capacity constraint, i.e. the tendered volume, our model would be better suited to predict investors' bidding prices than other models that neglect the capacity limit.

## F.5 Conclusions and policy implications

### F.5.1 Conclusions

We have developed a real options model for analysing investment decisions for offshore wind projects. Our approach has the advantage of providing a general and easily applicable model for analysing investment behaviour, while being flexible on the input side. Thus, it is suitable for dealing with multiple research questions. By modelling the gross margin as a combined stochastic process, we can accommodate several sources of uncertainty and still arrive at closed-form solutions. While acknowledging the simplifications and restrictions connected to this approach, we find our model very useful for comparative analyses, such as investigating implications of different support schemes on investment incentives.

To our knowledge, we are the first to have incorporated a capacity limit into such a real options model and have shown its practical relevance: the 'unconstrained model' would have in our case resulted in 2% too high investment thresholds and up to 13% too high capacities.

### F.5.2 Policy implications

We have shown that policy design cannot be based on cost-benefit analysis alone. Due to the strategic flexibilities and real options inherent in RE projects, the same support level might trigger very different investment behaviours under different support mechanisms. Policy makers need to take these effects into account whenever introducing a new support scheme or revising an existing one. Otherwise, investors might not react to market incentives as intended by policy makers.

We have analysed policy implications of three support schemes for a concrete case of offshore wind investment in the Baltic Sea. Here, we found that a TGC typically

requires an up to 3% higher profit margin than a FIT to trigger investment, while a FIT might lead to up to 17% smaller projects sizes.

The concrete policy implications are: when applying TGC schemes, policy makers should expect later investments and thus slower deployment rates than under FIT, while the individual projects will have larger capacities. How these effects are evaluated and addressed by policy makers, depends strongly on the specific policy goals and the regulatory and financial environment. We can, thus, only give conditional support scheme priorities, depending on the policy goals:

Policy goal	Priority		
	(1)	(2)	(3)
Fastest deployment	FIT	FIP	TGC
Largest project sizes	TGC	FIP	FIT

Hence, policy makers face a trade-off between fast deployment of smaller projects and slow deployment of larger projects (if the capacity limit is not reached) when choosing between support instruments.

The effect of slower deployment can be mitigated by compensating investors for the higher variability in profits, e.g. by increasing support levels (higher premiums or certificate prices). The desirability of this is, however, a completely separate discussion and not in focus of this paper.

Overall, we have shown that it is important for policy makers to consider real options in the design of policies, so that they trigger the desired RE investments effectively. We thus suggest the following step-wise approach in the implementation of support policies:

- (1) Explicitly define a priority list of policy goals.
- (2) Make a short list of potential support policy instruments to be applied.
- (3) Make a comprehensive analysis of representative investment options under all short-listed support schemes to fully understand investment behaviour.
- (4) Decide upon a support scheme and implement it. In case of FIT and FIP, determine the support levels so that option values are taken into account.
- (5) Monitor the markets closely and ensure that investment incentives from the support scheme actually realise as intended.

### F.5.3 Further research

We have implemented decision flexibilities in terms of capacity choice and investment timing. Also other flexibilities are thinkable. For example, large investment projects are often not undertaken as one, but can be split into several smaller investments, e.g. offshore wind parks are often planned in several phases. It could be beneficial to expand the model so that it can cope with sequential investments. This could also mitigate the issue of lock-in into smaller project sizes. Further improvement of the model could also include the introduction of seasonality and mean-reversion into the process. This may help to disclose even more of the investment dynamics for real offshore wind project - and the understanding of these is crucial when designing support policies.

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## F.A Nomenclature

**Table F.3:** Nomenclature

	Description
$a$	productivity factor (in production function)
$A$	variable investment cost
$b$	wake loss parameter (in production function)
$B$	fixed investment cost
$C_1, C_2$	part of the general solution to Bellman equation
$dz(t)$	a standard Brownian motion
$FIP$	fixed premium under a Feed-in Premium support scheme, per production unit
$FIT$	fixed tariff under a Feed-in Tariff support scheme, per production unit
$I(q)$	investment cost function
$q$	invested capacity
$\tilde{q}$	optimal unconstrained capacity choice
$\bar{q}$	upper capacity limit
$q^*$	optimal constraint capacity choice
$Q(q)$	function describing how production varies with capacity
$r$	discount rate
$S(t)$	electricity price
$t$	time period
$V(\pi; q)$	project value, total discounted future operational gross margin
$W(\pi)$	value of the investment option
$\beta$	root of the general solution to the Bellman equation
$\gamma$	compound factor (translates current revenues into future revenues)
$\mu$	drift of a stochastic process
$\pi(t)$	operational gross margin per unit capacity of the investment project
$\pi_{FIT}(t)$	operational gross margin per unit capacity under a Feed-in Tariff scheme
$\pi_{FIP}(t)$	operational gross margin per unit capacity under a Feed-in Premium scheme
$\pi_{TGC}(t)$	operational gross margin per unit capacity under a Tradable green certificate scheme
$\Pi(t, q)$	operational gross margin of the project
$\rho(t)$	wind power production
$\sigma$	volatility of a stochastic process
$TGC(t)$	variable certificate price under a Tradable green certificate support scheme, per production unit
$T$	lifetime of the project

## F.B Investment cost of the offshore wind park

For a realistic assumption on the variable investment costs (the costs depending on the size of the wind park), we use a bottom-up method developed by Dicorato et al. (2011). We slightly modify their equations in two ways. First, the real cost estimations are inflated from a 2009 level to a 2012 level, using the average annual inflation rate in the Euro area of 1.88%. Second, the equations presented in Dicorato et al. (2011) were mainly designed for estimating costs of an offshore wind park with



known size. Hence, some of the input parameters (such as number of medium voltage sections) were assumed given, whereas in our case, these should also be capacity dependent (or more precisely: dependent on the number of turbines installed).

The total investment costs of an offshore wind park consists of a number of different cost elements, namely wind turbine cost  $C_{WT}$ , foundation cost  $C_f$ , collection system cost  $C_{CS}$ , integration system cost  $C_{IS}$ , transmission system cost  $C_{TS}$ , reactive power regulation cost  $C_{RPR}$ , SCADA/EMS cost  $C_{SE}$  for controlling and remote monitoring, and project development cost  $C_D$  (Dicorato et al., 2011):

$$I(q) = C_{WT} + C_f + C_{CS} + C_{IS} + C_{TS} + C_{RPR} + C_{SE} + C_D \quad (\text{F.25})$$

In the somewhat simplified setting of Dicorato et al. (2011),  $C_{WT}$ ,  $C_f$ ,  $C_{CS}$ ,  $C_{SE}$ , and  $C_D$  [all in kEUR] are directly related to the size and layout of the offshore wind park. For the layout of the park, we assume sections of 10 turbines each with equal cable length. Because we need a linear equation as a result, we have to simplify by accepting that there will be non-integer results for the section number. This is not a significant issue for the research question in this paper, but it should be kept in mind when considering the approach and discussing the results of this analysis.

$$C_{WT} = 1.25 \cdot n_{WT} (3172 \cdot \ln(P_{WT}) - 403.5) \quad (\text{F.26})$$

$$C_f = 1.8 \cdot n_{WT} \left( 344 \cdot P_{WT} (1 + 0.02(D - 8)) (1 + 0.8 \cdot 10^{-6} \left( h \left( \frac{d}{2} \right)^2 - 10^5 \right) \right) \right) \quad (\text{F.27})$$

$$C_{CS} = \frac{n_{WT}}{10} (0.52 \cdot S + 106.6 + 392.5) \cdot l \quad (\text{F.28})$$

$$C_{SE} = 80.7 \cdot n_{WT} \quad (\text{F.29})$$

$$C_D = 50.33 \cdot n_{WT} \cdot P_{WT} \quad (\text{F.30})$$

where  $n_{WT}$  [-] is the number of wind turbines and  $P_{WT}$  [MW] is the capacity of a single turbine, thus,  $q = n_{WT} \cdot P_{WT}$ .  $D$  [m] is the water depth,  $h$  [m] is the hub height,  $d$  [m] is the rotor diameter.  $S$  [ $mm^2$ ] is the size of the array cables,  $l$  [km] is the cable length of each section.

In comparison to Dicorato et al. (2011), we have modified the factors for installation cost of wind turbines from 1.1 to 1.25 and for those of the foundations from 1.5 to 1.8 to account for a longer distance from shore and slightly deeper water levels than what was in the range of their investigation.

$C_{IS}$ ,  $C_{TS}$ , and  $C_{RPR}$  also depend on the regulatory regime for grid access and interconnection. In our case, we assume that the grid operator provides interconnection

for an offshore hub to which the wind park can connect. This implies that the investor will not have to bear any onshore transmission, substation, or reactive power regulation cost, other than a fixed connection fee. The wind park investor will have to bear the cost of a small offshore substation at which the wind park section cables of 36kV are collected and transformed for the 230kV export cable to the hub.

$$C_{IS} = \left( \frac{n_{WT}}{10} - 1 \right) 45.9 \cdot (A_{TR})^{0.7513} + 5611 + 72.4 \cdot \left( \frac{n_{WT}}{10} + 1 \right) + 2 \cdot 1398 \quad (\text{F.31})$$

$$+ 3710 + 22.8 + 2.22 \cdot n_{WT} \cdot P_{WT} + 2725 + 95.4 \cdot n_{WT} \cdot P_{WT} \\ C_{TS} = \left( 433.4 + 15.0 \cdot e^{(462.1 \cdot I_n \cdot 10^{-5})} + 392.5 \right) \cdot d_{wf} \cdot \frac{q}{150} + 26398 \quad (\text{F.32})$$

$$C_{RPR} = 0 \quad (\text{F.33})$$

where  $I_n$  [A] is the HV cable ampacity for a 230 kV offshore transmission cable to the hub with a length of  $d_{wf}$  [km]. We have modified  $C_{TS}$  slightly, to make the number of cables required dependent on the installed capacity in a simplified way. We assume that one export cable is required per 150 MW. Additionally, we add a fixed element covering for connection fee and switch gear. For simplicity, we assume that each section has its own MV/HV transformer with constant capacity  $A_{TR} = P_{WT} * 10$ .

Reformulating and sorting into terms dependent of  $q$  and terms independent of  $q$ , we get:

$$I(q) = q \cdot \left( \frac{1}{P_{WT}} \left( 3965 \cdot \ln(P_{WT}) + l \cdot (0.052S + 49.91) + 4.59 \cdot (A_{TR})^{0.7513} - 416.45 \right) \right. \\ \left. + 0.000104hd^2 + 11.39D + 2.48 \cdot 10^{-6} \cdot hd^2D + (0.1e^{0.005 \cdot I_n} + 5.51) \right) \\ \left. + 45.9 \cdot (A_{TR})^{0.7513} + 35724.2 \right) \quad (\text{F.34})$$

We assume an offshore wind park with specifications as described in Section F.3. Additionally, we have to define some more technical specifications. Table F.4 summarises all of these technical wind park input parameters.

**Table F.4:** Input parameters to the investment cost estimation

Turbine characteristics	Capacity	$P_{WT}$	3.6 MW
	Hub height	$h$	90 m
	Rotor diameter	$d$	120 m
Site characteristics	Water depth	$D$	25 m
	Distance to shore	$d_{wf}$	25 km
Park layout	Array cable length	$l$	10 km/section
	Size of array cable	$S$	140 mm <sup>2</sup>
	Ampacity of export cable	$I_n$	900 A

Thus, we arrive at the linear investment cost function (in million EUR):

$$I(q) = 2.8968q + 40.6575. \quad (\text{F.35})$$

For illustration, Table F.5 shows the resulting total investment costs for three exemplary capacity levels. The contributions of the cost elements are very much in line with the case shown in Dicorato et al. (2011). In comparison to costs listed in Sun et al. (2012), our total investment costs tend to be 50-60% higher, which is primarily due to higher estimates of integration costs and transmission system costs.

**Table F.5:** Investment cost for three exemplary capacity levels

million EUR	Park capacity No. of turbines		200 MW 55	400 MW 110	600 MW 220	Share of total investment
	Turbine cost	$C_{WT}$	252	503	1006	41-43%
	Foundation cost	$C_f$	194	387	775	31-33%
	Collection system cost	$C_{CS}$	31	63	126	5-6%
Integration system, Offshore substation		$C_{IS}$	38	61	108	5%
	Transmission system cost	$C_{TS}$	85	144	262	11-14%
	Reactive power regulation	$C_{RPR}$	0	0	0	0%
	Electrical devices	$C_{SE}$	4	9	18	1%
	Project development	$C_D$	10	20	40	2%
<b>Total investment</b>		<b><math>I</math></b>	<b>614</b>	<b>1188</b>	<b>2335</b>	<b>100%</b>

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PAPER G

# Achieving energy transitions: Reducing risk and creating an enabling environment

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**Abstract**

*The transition to a sustainable energy system is desired in many countries around the world and financial support schemes for renewable energy technologies are often deployed by policy makers to achieve such a transition. We argue, drawing from transition theory and the multi-level perspective, that an energy transition evolves in two phases: A first phase with focus on growth of the niche and a second phase with focus on integrating the niche technologies into the regime. We show, using policy analysis and economic considerations including risk aspects, that in the first phase it can be beneficial to establish support policy instruments which reduce risk for investors (such as feed-in tariffs) and to create an enabling environment for the new technologies, in order to prepare the crossover to the second phase characterised by significant market shares of renewable energies and related implications on regime level. In the second phase, policy focus shifts towards system and market integration of the new technologies, including changes in infrastructure, market rules, and the exploitation of related niches. Because policy targets are evolving alongside an energy transition, the evaluation of policy instruments also needs to be specific for each phase of the transition. In this paper, we propose a policy evaluation framework that takes different policy success criteria of each phase into account. Tailoring policies to the specific needs of each transition phase will lead to faster and less costly renewable deployment and increase the likelihood of achieving a successful transition towards a sustainable energy system.*

**Keywords:** Transition theory; Renewable energy; Energy policy; Innovation systems; Investor risk; Enabling environment

**G.1 Introduction**

A grand challenge of our age is to transform our global society from one which is dependent on fossil fuels to one which is sustainable and equitable. The transition of the energy system towards sustainability is thus targeted by many policy makers and members of society in many countries throughout the world. A transition towards sustainability generally requires policy intervention, because the new technologies that are desired to form the basis of a new, sustainable energy system (including technologies using renewable energy sources (RES), energy efficiency and demand management appliances) face various barriers to implementation. Therefore, we investigate *managed transitions*, in which policy makers determine targets and timelines for the transition, and actively intervene with certain policies in order to trigger deployment of desired technologies.

In the spirit of Cropper and Oates (1992), who find that “policy structure and analysis is a good deal more complicated than the usual textbooks would suggest”, we propose an approach to policy evaluation that goes beyond the ‘standard’ approach of cost-benefit analysis. Using transition theory, we broaden the evaluation perspective to

also take into account dynamic processes and related market imperfections. The insight that policies not only have to be effective and efficient in a static sense, but that they also need to deal with long-term normative goals for systemic change, has recently entered innovation systems thinking and policy making (Weber and Rohrer, 2012). Taking this perspective, the question ‘which policy is better’ cannot be answered any more - but rather the question of ‘what policy specifications and combinations are better to achieve which targets at what times’? We argue that for a successful energy transition, policies need to be successful not only in achieving low cost deployment of the new technology at micro level, but also in triggering changes of the existing socio-technical system at a macro level. As discussed by Weber and Rohrer (2012), the capability of policies to initiate larger changes in the system is important for a successful transition to a fully sustainable energy system.

This paper draws from two lines of research. First, literature on transition theory, strategic niche management and innovation systems serves as the general frame for our analysis (Rip and Kemp, 1998; Kemp et al., 2001; Smith and Raven, 2012; Meadowcroft, 2009; Verbong and Geels, 2010; Pollitt, 2012; Markard et al., 2012). Second, literature on the assessment of different policy instruments helps us to support our economic argumentation (Weitzman, 1974; Cropper and Oates, 1992; Just et al., 2004; Menanteau et al., 2003; Miller et al., 2013).

Miller et al. (2013) predict that policies will evolve during the transition from being focused on maximum deployment (‘first-generation’ drivers) towards having more nuanced designs including the reduction of investment risk, minimisation of policy costs and market integration (‘next-generation’ drivers). We argue in this paper that it is beneficial for policy makers to focus on these nuances in policy design as early as possible.

## G.2 Managed energy transitions: Phases, economics and risks

Transitions are gradual, continuous processes in which society (or a complex sub-system of society) changes in a fundamental way over several decades (Rip and Kemp, 1998; Rotmans et al., 2001). Rotmans et al. (2001) emphasise that policy makers can influence, but never entirely control the direction, scale and speed of transitions. Transition management thus focuses on creating policy corridors to ensure that key variables remain within acceptable limits so that the socio-technical system overall develops in a desirable direction (see Rotmans et al., 2001). Risk analysis and risk management is therefore an integral part of transition management. Successful transition management has four major characteristics: (1) Long-term thinking when



shaping short-term policy; (2) Thinking in multi-domain, multi-actor and multi-level terms; (3) Focus on learning and bringing about system innovation alongside system improvement (learning-by-doing and doing-by-learning); (4) Focus on a wide playing field (keeping open a large number of potentially beneficial development paths) (Rotmans et al., 2001).

Often, transitions are analysed by adopting a multi-level perspective (MLP) (Geels, 2004), consisting of three interlinked levels: (1) Niches: the micro level, where new technologies emerge; (2) Regime: the meso level, consisting of technical infrastructure and other material elements, rules and regulations as well as actor networks and social groups; (3) Landscape: the macro level, the exogenous environment including macro economy, policy making and cultural patterns that all influence the dynamics at the niche and regime levels. From historical experience, we know that transitions only occur when developments at all three levels link up and reinforce each other in feedback loops (Geels, 2004).

Niches are the crucial level for triggering the start of a transition. At niche level, protected spaces can be created in which the new technology can blossom. In niches, the viability of a new technology is demonstrated, a system of providing financial means is created, and interactive learning processes and institutional adaptation are set in motion (Kemp et al., 1998, p.184). A whole set of literature revolves around ‘strategic niche management’ (e.g. Kemp et al., 1998; Kemp et al., 2001; Jacobsson and Lauber, 2006; Schot and Geels, 2008). Risk reduction is a central aspect here: Stabilising revenue streams and technology-specific price guarantees are a major source of protection (Finon and Perez, 2007). Niches can break through on regime level in two ways: Either, they eventually become competitive under the selection environment and rules of the existing regime (‘fit and conform’); or they challenge the existing regime in ways so that its selecting criteria, rules, and institutions need to be adapted (‘stretch and transform’) (Smith and Raven, 2012). In this, it is crucial that external developments from landscape level create pressures on the regime that favour the niche technology (STRN, 2010), such as pressures from policy interventions. In energy transitions, a ‘stretch and transform’ alignment is generally required due to the very different technical and economic characteristics of RES as compared to conventional thermal power plants (see e.g. Verbong and Geels, 2007). At any point in time, several new technologies (and practices) are developing in different niches. When different related niches start reaching into the regime, they can become either hindrance or leverage for each other. In a successful transition to a sustainable energy system, many of these related niches need to gradually arise, developing and linking together, so that they eventually combine at the regime level into one overarching sustainable energy system.

There have been various criticisms of the MLP (as explored by Geels, 2011), some of which we agree with. Nevertheless, we find the notion of the three levels (niche, regime, landscape), and the inter-linkage between them a useful general description

for the purpose of this paper.

### G.2.1 Phases of the transition

The dynamic process of an energy transition is best analysed in different phases. The first to define different phases in technological change was Schumpeter (1939), differentiating invention, innovation, and diffusion. Rotmans et al. (2001) describe transition phases as (1) Predevelopment, (2) Take-off, (3) Breakthrough, (4) Stabilisation. Strategic niche management analyses changes in (1) a normative phase, (2) a take-off phase and (3) a market phase. In the normative phase, the main targets for a new technology are reducing investment cost and increasing production volume. In the market phase, there is more focus on the deployment and market performance of the technology. Drawing from these approaches, this paper views energy transition in two phases: A first phase with focus on growth of niches (thus comprising the predevelopment or normative phase and the take-off phase), a second phase with focus on efficient integration and enabling innovation (similar to the market phase and thereafter, comprising both breakthrough and stabilisation). Later, there might follow a third phase, in which a society (as a whole) becomes truly sustainable.

In our first phase, policy makers create protected spaces in niches to trigger the deployment of RES. In a liberalised market, adequate investment incentives for private investors must be established, i.e. through support schemes. A focus on growth in the niche is crucial but not sufficient. A steadily growing share of variable RES has implications for power markets, grid operation, and infrastructure needs (Miller et al., 2013; Mitchell, 2014). It is thus important that policy makers deal as early as possible with upcoming requirements to adapt the regime infrastructure (e.g. grid reinforcements), and trigger development in related niches (e.g. technologies providing flexibility). Therefore, coordinated management of related niches as well as preparation for system adaptation is crucial for the success of the first transition phase and a smooth transition to the next phase.

The crossover to transition phase 2 begins when the niches have grown so that the new technologies significantly challenge or transform the regime. Then the transition stands at a crossroad: Either, the regime will develop resistance to further growth of the niche, preventing it from becoming a fully integrated part of the system; or the regime will embrace the new technologies. Only when a regime has overcome initial resistance to the new technologies (technically, socially and politically), the transition can enter phase 2. We define the start of transition phase 2 so that all of the following three conditions are met: (1) System and network operations have adapted to dealing with a large share of RES; (2) Market design has been adapted to value characteristics that complement the new technologies (such as flexibility); (3) Technology costs of the new technologies have come down significantly to almost competitive levels. The

adaptation of the regime in areas that are directly or indirectly related to the niche is thus a crucial characteristic of transition phase 2. System and market integration aspects now become a main focus of policies. Usually, a whole cluster of policies is required to create an enabling environment which allows successful integration.

It should be noticed that the two phases can overlap in a step-wise introduction of different new technologies and with different stages of maturity. Typically, a regime would be in phase 2 for some technologies, whilst still being in phase 1 for others.

### **G.2.2 Support policies in managed transition: Does it make sense economically?**

From an economic perspective, the active management of an energy transition favouring new technologies based on renewable energies can be justified when they in the future will be more beneficial for society than conventional technologies (based on coal, natural gas) or other known options (such as carbon capture and storage), and when RES technologies would not be developed sufficiently by the market alone (Kumbaroglu et al., 2008). For RES technologies, sufficient development through market forces is not likely. As Jaffe et al. (2004) emphasise, new environmentally friendly technologies are “doubly underprovided by markets” because of two distinct types of externalities: Negative externalities (pollution) of conventional technologies (if not sufficiently internalised) and positive externalities (knowledge spill-over) of new technologies.

Negative environmental externalities are, according to the ‘polluter-pays’ principle (OECD, 1972), best internalised by increasing the cost of the polluting units. In this line of argument, support of RES is regarded as a ‘second-best-solution’ as compared to i.e. a carbon tax. Others however argue that it might often be necessary to use RES support policies because the ‘correct’ tax level might not be known or would be required at such high level that public acceptance issues arise. Moreover, the positive externalities of knowledge spill-over and other barriers that new immature technologies face cannot be efficiently overcome by pricing pollution (Jaffe et al., 2002; Menanteau et al., 2003; Finon and Perez, 2007; Kalkuhl et al., 2013). Additionally, other market failures such as incomplete markets play a role.

Acknowledging the necessity of renewable support, one could argue that only research and development (R&D) should be supported. For example, Frondel et al. (2010) suggest that it would be beneficial in Germany to wait with the deployment of costly RES technologies until costs are brought further down by R&D. On the other hand, energy transitions are often used to combat negative effects from climate change. For this, a timely replacement of conventional pollution technology is crucial - policies are required which can deliver fast deployment of renewables (see e.g. Jacobsson

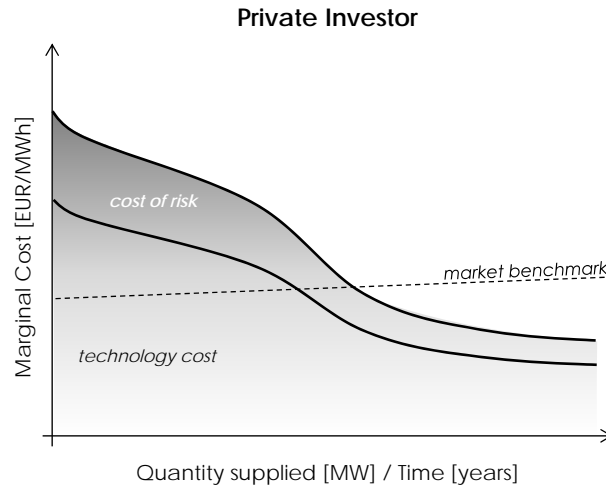
and Lauber, 2006). Moreover, research on innovation systems suggests that without deployment, energy innovation processes are less effective (Gallagher et al., 2012).

Regarding support for deployment of renewable energies, lump-sum support payments (such as investment grants, paid out as upfront sum, i.e. 500 EUR/kW) generally figure as the most efficient ones in the literature, because they minimise market distortions (see Andor et al., 2012). However, in reality, lump-sum support is often only used as supplementary support. The most commonly applied major support schemes for electricity generation from renewable energy sources (RES-E) in Europe are output based (paid out per generated unit, i.e. 50 EUR/MWh) (European Commission, 2011; Kitzing et al., 2012). Because of their dominance in practical policy implementations, we will focus on the most common output based instruments: feed-in tariffs (FIT) and quota schemes with tradable green certificates (TGC). Traditional FIT schemes are technology-specific price-control mechanisms that offer a guaranteed price to eligible producers, most often in combination with priority dispatch and exemption from participation in balancing markets. Traditional TGC schemes are technology-neutral quantity-control mechanisms that oblige energy suppliers to have a certain quota of renewable energy in their portfolio, which can be acquired in form of green certificates from eligible producers on a dedicated certificates market. More recently, also feed-in premiums (FIP) are coming in use. FIP are guaranteed add-ons to market prices.

### G.2.3 Renewable energy technologies from an investors perspective

Figure G.1 describes a typical cost development of a new technology over time as seen by a private investor. The total costs of new projects tend to be high in the early stages of technology development and decrease with increasing deployment of the technology (Jamassb and Köhler, 2007). We have split the total cost into ‘technology cost’, and ‘cost of risk’. We use this distinction, because the two elements, although related, can be distinctly addressed by specific policy measures, and are important to our argument about how technologies should best transfer from phase 1 to phase 2.

Technology cost reductions stem from two different general sources (based on Menanteau et al., 2003): 1) technical change, including reduction in investment cost and improved technical performance; and 2) systematic effort to benefit from economies of scale, use of very best sites available, operational optimisation, organisational learning, synergies within companies, etc. (also called ‘induced progress’ in the literature, Finon and Menanteau, 2004). Achieving technical change often requires R&D investment (technological innovations), whereas the more ‘organisational’ cost reductions are effectively triggered through competition (pressure between projects of available technologies). Menanteau et al. (2003) show that traditional FIT schemes generally



**Figure G.1:** Cost of a technology from an investor's perspective, development over time

provide higher incentives for domestic innovation and R&D, whereas technology-neutral TGC schemes perform better on the 'organisational' cost reductions through their increased competitive pressure.

In traditional FIT schemes with long-term price guarantees and without a cap on overall support, RES projects experience less competitive pressure than in TGC schemes, where all projects receive the same certificate price no matter for which RES type, where or when they are built. On the other hand, the technology-specific long-term price guarantees in FIT schemes can spur more technological innovation, as predictability of future surplus from cost reductions is crucial for developers to undertake the often significant upfront R&D investments required for technological innovations (Menanteau et al., 2003). Under TGC schemes, future prices are unknown and this lack of market anticipation decreases R&D incentives - it is strategically better to focus on 'organisational' improvements and procure new and improved technologies externally (see Menanteau et al., 2003; Finon and Menanteau, 2004). Johnstone et al. (2010) have shown with an empirical patent analysis that innovation under TGC schemes is mostly related to technologies close to market-competitiveness, whereas FIT spur innovation in more immature technologies. However, Söderholm and Klaassen (2006) show that the innovation effect of FIT schemes depends highly on efficiently set tariff levels: If they are too high, then FIT provide fewer incentives for cost reductions. In Europe, we have seen that in countries with FIT schemes, strong domestic technology industries have developed (Denmark, Germany, Spain), whereas countries with TGC schemes often procure equipment from abroad (UK), as shown by Söderholm and Klaassen (2006) for wind energy.

Cost of risk tends to be highest in the beginning of a technology learning curve. It will be reduced throughout the learning process. We consider two different types of risks: market risks and non-market risks. We can distinguish between three different

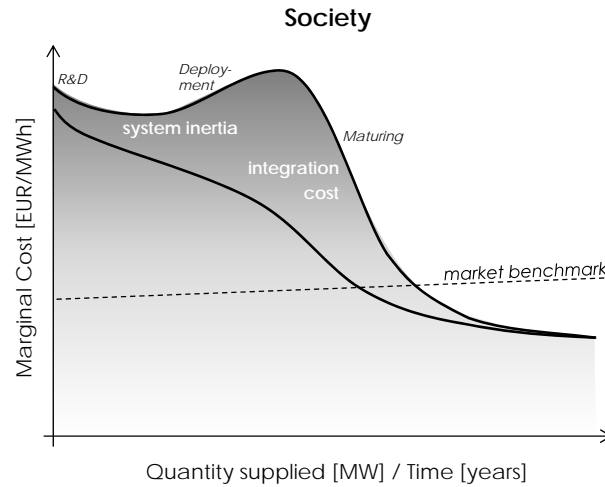
energy-related markets (Klessmann et al., 2008): (1) (future) power markets, (2) balancing markets, (3) support markets (if existing). All three markets entail two kinds of risks: price volatility and volume risk, as also discussed in Mitchell et al. (2006). Additionally, RES-E investors also operate on the capital market to secure financing for the investments. Non-market risks are technical, social or political. Such risks emerge from the technology itself (e.g. efficiency, yield, reliability, hazards), the project and firm (schedule, contract strategy, competence of employees, safety issues, etc.), the social environment (labour availability and skills, employment law, public acceptance), regulatory issues (permitting procedure, system rules), the legal framework (laws, recourse, remedy, income taxation, allowances) and political initiatives (regime stability, changes in energy and climate policy, provision of infrastructure, etc.) (adapted from Michelez et al., 2011).

Most risks are common to many investors in a country (e.g. regime stability, taxation rates, etc.) and will not be changed in light of a managed energy transition. There are however a number of risks that can be addressed to increase the success likelihood of an energy transition, as discussed below.

#### **G.2.4 Renewable energy technologies from a societal perspective**

The costs of a new technology differ for society and private investors. This is because the latter is concerned only with direct project costs whereas society also incurs all related development and system costs. Ueckerdt et al. (2013) have developed a comprehensive framework for estimating system integration cost of variable renewable energies. These include expenses for grid infrastructure, balancing services, reserve requirements and additional flexibility from thermal power plants. Ueckerdt et al. (2013) calculate that integration cost steadily rise with increasing shares of variable renewable energies (up to 40% market share). Their analysis relates though mostly to a static environment. When taking system adaptation effects and technology learning into account, we argue that, conceptually, a turning point should be expected in the cost development, after which system integration cost and grid infrastructure are marginally decreasing with more deployment of the new technology. We illustrate this effect conceptually in Figure G.2.

The risks that society is concerned with are quite distinct from private investors' risks. E.g. contractual issues or market price volatilities are generally of no concern on a societal level unless they would affect economic output, social welfare or efficiency of a market. Society is e.g. more concerned with the stability of state income and budget, so that social services can be upheld. Political risks are not so much related to the stability of the support regime (as is the concern of a private investor), but more to the incentive structure that the policies provide and the distortions that they might cause. There are risks related to the evaluation of pollution effects and



**Figure G.2:** Cost of a technology from a societal perspective, development over time

related health costs and similar. Society may be concerned about a healthy domestic industry, about unemployment and a good trade balance. Policies are often used to mitigate these concerns, so that policy targets often combine a multitude of different societal objectives.

### G.3 Efficiency and effectiveness of policies in managed transitions

Often, the effectiveness and efficiency (or cost-effectiveness) of policies is evaluated on the basis of static cost-benefit considerations. We argue that especially two aspects should not be neglected in policy evaluation: Risk aspects and dynamic processes. Risk aspects are an area of increasing attention in policy making (see e.g. Gross et al. 2010). Klessmann et al. (2008) show that the level of exposure to risk is a significant factor for differences in effectiveness and efficiency of renewable policy instruments.

In this section, we present some conceptual considerations regarding risk aspects and dynamic processes that serve as basis for the policy evaluation framework presented in Section G.4. We first look at market risks and discuss how different policy instruments perform in terms of risk reduction. We then show that the reduction of market risks can help to increase deployment rates of RES-E. Subsequently, we explore if this increased effectiveness comes at the expense of lower efficiency. Finally, we briefly discuss non-market risks.

### G.3.1 Reduction of market risks

In power markets, future prices are unknown and cannot be fully secured through financial contracts (Forwards are traded only for up to 3-6 years into the future). RES-E producers also face volume risks due to uncertain production and potential constraints in marketing the production, either because of market design (bidding sizes and time blocks) or the physical grid infrastructure. Traditional FIT schemes provide priority feed-in and guaranteed production off-take, so the latter element of volume risk is minimised. Also the price risk is decreased to a minimum thanks to the guaranteed price level. In FIP and TGC schemes, RES-E producers are fully exposed to power market risks.

Balancing markets have also unknown future prices (which typically cannot be hedged by financial contracts) and the risk of imbalance volumes is especially high for intermittent energies: RES-E producers are exposed to imbalances from forecasting errors or performance issues (depending e.g. on the gate-closure time of spot markets). Traditional FIT schemes exempt RES-E producers from participating in balancing markets, so they are not exposed to related risks. In some more recent implementations of FIT (sliding premium systems), as well as in FIP and TGC schemes, RES-E producers are fully exposed to balancing market risks.

Support markets only exist when created by a respective RES support scheme. For FIT and FIP, no support markets are necessary. For TGC schemes, a market to trade green certificates is established. On this market, RES-E producers are exposed to volume risk due to uncertain production, and price risk as certificate prices depend on the demand and supply balance related to the quota set by government.

On the capital market, risk reduction can happen through ‘financing support’ measures, as described by Kitzing et al. (2012): provision of reimbursable equity or venture capital from governmental institutions, low interest loans, equity guarantees, loan guarantees and securisation products. Weiss and Marin (2012) find that providing long-term revenue stability (as in traditional FIT price-control schemes) is critical for facilitating the financing of capital-intensive renewable energy projects and thus for their successful deployment.

Traditional FIT schemes are thus usually the policy instrument that reduces market risk most, due to their inherent risk reducing characteristics. Therefore, the literature describes the implementation of FIT schemes often as ‘low risk’ approach, and TGC schemes as ‘high risk’ approach (see e.g. Klessmann et al., 2008). However, these inherent characteristics can be substantially altered by design specifications (e.g. sliding premiums or caps and floors), so each instrument can also be implemented in a ‘low risk’ or ‘high risk’ way. In fact, Ragwitz et al. (2011) show that a gradual convergence of key properties in FIT and TGC implementations can be observed in



Europe, with trends to provide differentiated technology-specific support, to enact quantity controls, and to introduce elements of market exposure.

Whatever policy is employed, it should be flexible enough to be slowly adapted according to the changing requirements in the different transition phases. In transition phase 2, system integration becomes important, which implies two things: (1) the protection of niche technologies must be slowly reduced, so that RES-E become a more and more ‘normal’ part of the overall energy system, (2) the regime level has to be adapted, so that it accommodates the needs of the new technologies. The success of TGC depends on a well-functioning certificate market. Implemented changes almost always affect the whole market, and frequent changes can have disturbing effects on its functioning. In FIT schemes on the other hand, policy makers have strong control over the specific technologies. Changes can be implemented step-wise and if announced timely, they will not disturb the market place in the same way as in TGC schemes. More research on this issue would be beneficial to support this point with analytical or empirical evidence.

### **G.3.2 Reduction of market risks: effective in delivering deployment**

Effectiveness is one of the most important success criteria for policies, generally defined as the ability of a policy (or policy package) to deliver the desired outcome at the desired time. However, the desired outcome can be defined in different ways. Two of the most usual definitions are: (1) Targets are set or perceived as minimum levels (deployment over the set target is still desirable). In this case, such policies are considered most effective that deliver maximum deployment within a given time period (this corresponds to the definition of the European Commission (2008); and RES target setting of many countries; see also Haas et al., 2011); or (2) Targets are set as fixed or even maximum levels. In this case, such policies are considered most effective that deliver exact target achievement. Such target setting often occurs in situations where other policy objectives than RES deployment (such as cost-effectiveness or system integration) become dominant.

Some economic studies conclude that there should be no difference in deployment quantity from different policy instruments (such as TGC or FIT) at a given support level (see also Menanteau et al., 2003), as long as the support levels are set efficiently. Those studies base their argumentation mostly on classic welfare economics and implicitly neglect issues such as incomplete markets, risk-aversion and transaction costs.

In real energy systems, markets are often incomplete: No perfect hedges are available for RES-E developers and investors, leaving them most often involuntarily exposed to certain market risks. Assuming risk-aversion of investors and other market agents,

the involuntary exposure to market risks will entail costs. A reduction of these risks will have several effects for investors (see also Simkins and Simkins, 2013, p.385f): A firm with lower risk projects can generally achieve greater debt capacity and lower cost of debt. Alternatively, the cost of equity could be reduced. A firm with more stable income flows has lower cost of liquidity management and other measures that shall avoid financial and economic distress<sup>1</sup>. When assuming imperfect markets, the reduction of market risks can also help to reduce transaction costs and reduce the exposure to risks that cannot be hedged.

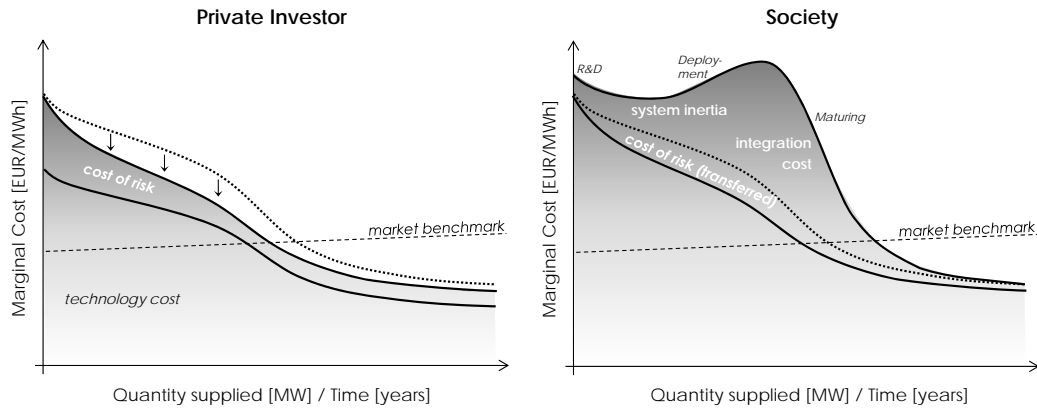
The emerging field of ‘transaction cost economics’ tries to assess private costs and risks associated with transactional complexity, which in reality can be substantial. As Finon and Perez (2007) have analysed, FIT schemes offer a maximum of clarity and simplicity for transactions between producers and purchasers, because much is defined by the regulatory arrangement. This reduces overall transaction costs. In TGC and also FIP schemes, producers and (obligated) buyers are forced to seek long-term contracts or vertical integration to avoid market risk. Efficiency losses become apparent if transaction costs are considered in the economic assessment (Finon and Perez, 2007). Based on an empirical analysis for European countries between 2002-2010, Jaraitė and Kažukauskas (2013) have shown that in TGC schemes more market imperfections are present than in FIT schemes, because of higher investment risks, higher capital constraints and higher transaction costs.

Another often neglected factor is that firms are not always ex-ante rational decision makers. Also firms have to go through a learning process and understand how to assess and cope with the risks associated with new technologies (see Ramesohl and Kristof, 2002). Especially in the beginning of this learning phase, perceived risks may be significantly higher than actual risks. This could be prohibitive for some projects and costly for others. Risk reducing policies can also help to give a comforting signal to developers, investors and financial partners in times when the risk assessment of new technologies is still in the learning phase.

The cost reducing effect of exposing investors to less market risk is illustrated in Figure G.3 on the left hand side. However, market risks do not disappear when reduced for private investors: they are merely transferred to other actors. A net cost reduction on societal level would be very small if present at all, as conceptually illustrated in Figure G.3 on the right hand side.

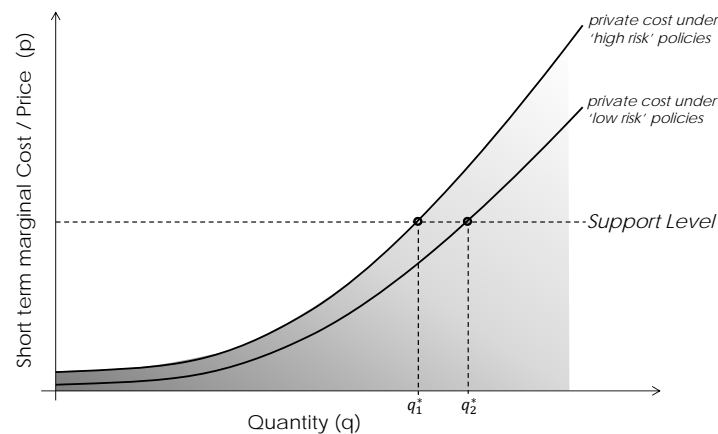
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<sup>1</sup>In classic economic theory, active liquidity management and related costs of risks are not recognised as relevant part of investment considerations of firms (Modigliani and Miller, 1958). Empirical studies however show that it is common practice in firms to incur additional cost from activities targeted at avoiding financial and economic distress (Acharya et al., 2012).



**Figure G.3:** Transfer of market risks from investor to society

The risk reducing effect of policies influences private decisions so that investors more readily invest at lower risk premiums. The private costs of investment becomes lower and more investment occurs at a given support level (compare also Miller et al., 2013). Figure G.4 illustrates the effect of increased deployment quantity from a ‘low risk’ as compared to a ‘high risk’ policy. Many studies have shown that FIT schemes can lead to an increased deployment as compared to TGC schemes, based on empirical policy analysis (Mitchell et al., 2006; Butler and Neuhoff, 2008; Klessmann et al., 2008; Haas et al., 2011), and also more theoretically based on finance theory and a real option approach (Boomsma et al., 2012; Kitzing et al., 2014).



**Figure G.4:** Illustrative marginal direct cost curves for a certain technology under different policies, resulting in different deployment quantities for a given support level

Risk reduction is thus clearly a policy strategy to achieve maximum deployment at given support levels. If maximum deployment is the policy objective, then those policies reducing most risk are often the most effective ones. As discussed in Section G.3.1, FIT schemes generally reduce most risk for RES-E. But does this effectiveness

come at the expense of reduced efficiency? In the next section, we deepen our analysis by exploring efficiency effects of different policy instruments.

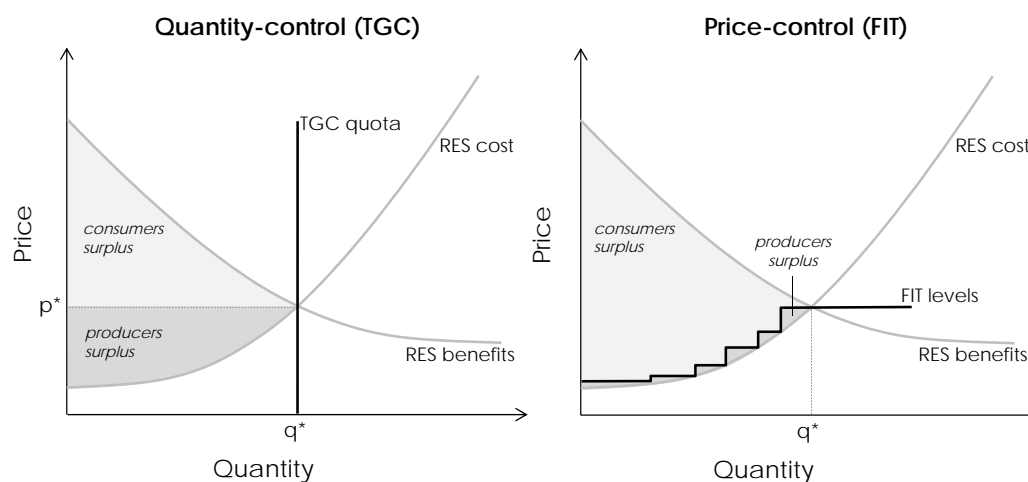
### G.3.3 Reduction of market risks: is it also cost-effective?

Del Río and Cerdá (2014) discuss two different understandings of efficiency (or ‘cost-effectiveness’) in the RES-E literature: Some follow classical welfare economics, where efficiency evolves from market forces and competition, leading to a mix of technologies that minimises production cost. Studies adhering to this line of thought tend to favour technology-neutral, competitive instruments with volume caps (like traditional TGC schemes). Others find those policies ‘efficient’ that minimise support cost (see also the definition of the European Commission, 2008), implicitly assuming that policy makers are not only concerned about minimising production cost but also how welfare is allocated between producers and consumers (as an equity issue). These studies tend to favour technology-specific, price-guaranteeing instruments (like traditional FIT schemes). In our analysis of this issue, we will start from the classical welfare economic argument and will then broaden our perspective to incorporate effects from dynamic processes that are central to the transition framework.

In a classical economic view, only those outcomes are efficient that adhere to the equi-marginal principle (all technologies are deployed until the same marginal cost). In TGC, this occurs implicitly by controlling the total quantity ( $q$ ) of deployment from the desired technologies and competition amongst all technologies. Eventually all projects with costs below  $q^*$  will be realised (see Figure G.5). The resulting support market price is  $p^*$  for all RES-E production. On the other hand, the price levels in a FIT scheme are exogenously determined by government. To achieve a comparably efficient outcome, the levels have to be designed so that no technologies above  $p^*$  or  $q^*$  are being deployed. In reality, this is not always the case, for example there might be a strategic interest in promoting photovoltaics even if they are still expensive. We will be setting this aside for the moment, assuming that governments only deviate from this principle of staying below  $q^*$  and  $p^*$  as a conscious decision at the expense of short-term market efficiency.

As illustrated in Figure G.5, for both TGC and FIT policies, generation costs are minimised (only projects below  $q^*$  are realised) with the results that net social welfare is equally maximised (sum of shaded areas is the same).

So, following classic welfare economics, one would be indifferent regarding instrument choice at this stage. This conforms with textbook teaching that risk reduction in form of price stabilisation (as in FIT schemes) is neutral on overall welfare under price uncertainty with predetermined volumes (Just et al., 2004, p.470f).

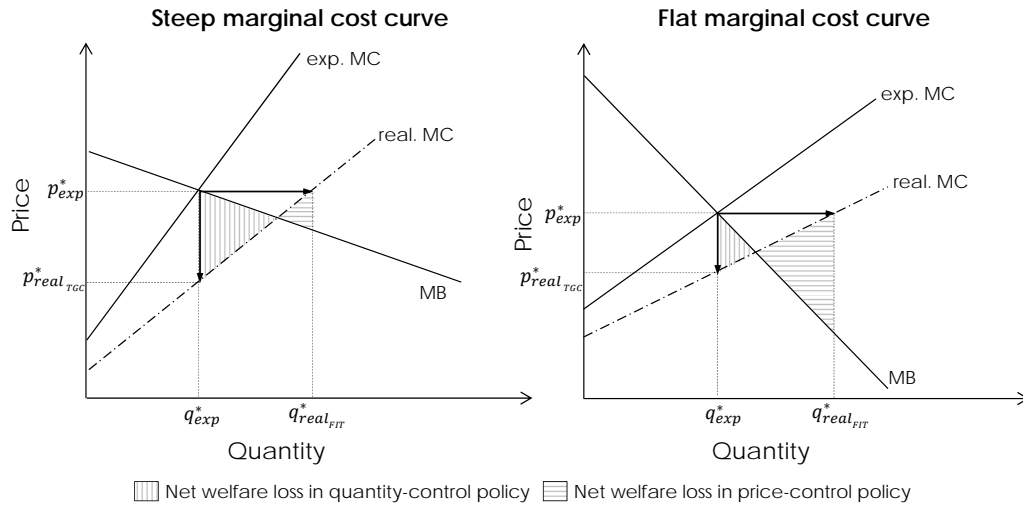


**Figure G.5:** Marginal cost and benefit curves, distribution of social welfare between producers and consumers for the two major generation support instruments FIT and TGC (see also Haas et al., 2011)

However, the two policies differ significantly in their allocation of welfare (surplus) to consumers or producers, respectively. In the FIT scheme, consumer surplus is much larger than in the TGC scheme. This reallocation is achieved by minimising support payments, while keeping up the investment incentive (thus minimising the difference between the respective FIT level and the RES cost). As a result, FIT minimises support costs as well as producer surplus, whereas the TGC doesn't. Contrary to general recommendations by welfare economists, policy makers are in reality often concerned about these re-allocation effects (see e.g. the discussion in Germany, as described in Lauber and Jacobsson, 2013), and will try to minimise producers surplus to the benefit of consumers (del Río and Cerdá, 2014). Then, a technology-specific price-control mechanism should be chosen because it can best mirror the specific costs at any time.

We have not yet taken into account uncertainty related to the cost and benefit functions. The risk of setting the quota or the tariff at an inefficient level is apparent. In this case, the optimisation problem changes from finding the right price level or quota that maximises net social welfare to finding the policy that maximises the expected net social welfare while minimising society's exposure to undesired outcomes. When price levels or quotas are set at an incorrect level, they can lead to net welfare losses (also depicted as 'regulator's regret'). Weitzman (1974) has developed a framework for analysing this effect for quantity- and price-control instruments of environmental policy. We illustrate his findings in Figure G.6 adapted to renewable support instruments.

Figure G.6 shows the welfare implications of uncertainty described by Weitzman (1974) for two relations between marginal cost curve (MC) and marginal benefit



**Figure G.6:** Risk of net welfare loss under cost uncertainty for quantity- and price-control policies, for a marginal cost curve steeper than the benefit curve (left), and vice versa (right) (based on Weitzman, 1974)

curve (MB): A relatively flat MC curve (on the left hand side) and a relatively steep MC curve (on the right hand side). In both cases, we compare the net welfare losses for a price-control (FIT) and a quantity-control (TGC) policy. If the realised marginal costs (real. MC) are lower than expected (exp. MC) (which is a reasonable assumption from recent experiences with RES-E cost developments; Edenhofer et al., 2012), then a FIT will lead to higher than expected quantities deployed ( $q_{real\_FIT}^* > q_{exp}^*$ ), whereas a TGC will lead to lower than expected prices ( $p_{real\_TGC}^* < p_{exp}^*$ ). Both effects cause net welfare loss.

However, the amount of net welfare loss differs significantly: If the MC curve is steeper than the MB curve, the TGC leads to larger net welfare loss (in Figure G.6 on the left hand side, the shaded triangle for TGC is larger than for FIT). If the MC curve is flatter than the MB curve (right hand side of Figure G.6), the FIT leads to larger net welfare loss and thus higher ‘regulator’s regret’.

Finon and Perez (2007) report that, although the shape of the marginal cost curve cannot be known precisely, several studies suggest that marginal cost curves of RES-E are rather flat (near the equilibrium where it matters). This would imply that a TGC scheme should be preferred. However, we have a more differentiated view. Acknowledging that the shape of the marginal cost and benefit functions are very difficult to estimate, because they comprise different elements, not all of which are revealed as market prices, we argue the following: A small niche comprising different and still immature technologies has most probably a comparably steep marginal cost function: Not many different equipment manufacturers or project developers are active. Plant capacities for manufacturing equipment still need to be established and still relatively few sites for renewable energy are developed. The total amount

of available projects is thus limited and partly only realisable at very high cost. It takes time to build up related infrastructure. On the other hand, the marginal benefit curve is rather flat as often, marginal benefits from positive externalities are rather stable (Cropper and Oates, 1992). The steepness of the marginal cost curve however decreases with the development of the technology and the growth of the niche. More manufacturers and investors enter the market, more sites are explored, and knowledge will be shared. The marginal cost curve may thus become flatter after certain time of niche development. Given this, a FIT scheme would be preferable in the first phase of a transition, at least until the relation of MC and MB curves has changed.

In light of the uncertainties about the marginal cost and benefit functions, as well as about the relative positioning of the curves towards each other (uncertainty about which curve is steeper at what times), Roberts and Spence (1976) and Weitzman (1978) have shown that the expected and realised net social welfare might be best optimised by using price- and quantity-control instruments in tandem, where each policy acts as a ‘safeguard’ against the potential pitfalls of the other.

Moreover, the validity of the above conclusions regarding efficiency properties of the different policy instruments depends heavily upon the degree to which a perfectly competitive equilibrium exists for the market (see Cropper and Oates, 1992). In reality, a number of market imperfections exist that distort the outcome. Market imperfections come in form of monopolies or oligopolies, imperfect information and transactions costs, as well as complex objective functions.

An example of a complex objective function is when policy makers have to make a trade-off between different policy outcomes: If an important political target is to achieve as much renewable deployment as possible within a certain time horizon, then the perceived benefit from additional deployment might more than compensate the net welfare loss associated with a too high price paid. Also other (external) payment obligations may be relevant, such as in Europe potential infringement penalties if a Member State cannot achieve its binding renewable targets by 2020.

Transaction costs are most often not considered relevant in the analysis of economic efficiency (Griffin, 1991). We have discussed some implications of neglecting transaction costs in Section G.3.2 above. Transaction costs also play a role in efficiency issues stemming from risk aspects. In the state-preference model of economic theory, if differences stemming from risk exposure occurred, individuals would trade with each other until differences are eliminated (‘balance of the states’) (Just et al., 2004). However, if market imperfections exist and these trades cannot be fully conducted, competitive markets cannot converge in the one market price that is required to reach the social optimum. In this case, it might be socially beneficial to take risk away from individuals and re-allocate them to other individuals that have better hedging options or to combine it into one socialising pool. In an energy transition,

this could for example be protecting renewable energy producers from market price risks with a price guarantee. However, this kind of risk reduction can entail a situation of moral hazard and adverse selection problems, in which the beneficiaries adopt socially adverse behaviours because of their protection (Just et al., 2004). In our case, renewable energies that are fully protected from market signals will not decrease their production in situations of oversupply and negative market prices. A pooling of risk to the benefit of private investors can thus only be accepted for a limited time in a controlled niche in order to achieve certain important targets.

Until now, we have implicitly assumed that there are no differences in how the different agents evaluate risks. When assuming differences in risk-aversion by investors, it suddenly matters which risks the different agents are exposed to and how they personally evaluate it. A way to economically analyse such effects is by using utility theory, and calculating the specific benefits to each individual (see e.g. Just et al., 2004). Without going into detail with this, many applications of utility theory have shown that the classical argumentation does not hold, and it often does matter for overall welfare if surplus is allocated to producers or consumers and who is exposed to which risks (see e.g. Just et al., 2004).

Finally, the question of what is efficient in the short term differs significantly from the question of what is efficient in the long term. This is often referred to as the difference between ‘static efficiency’ and ‘dynamic efficiency’ (Finon and Menanteau, 2004). The different incentives to reduce technology costs are important here (see Section G.2.3). Weber and Rohrer (2012) define it as ‘directionality failure’, if policies fail to contribute to a particular direction of transformative change. To avoid this failure, often technology specific policies are needed to provide more targeted impulses (Jacobsson and Bergek, 2011).

We can conclude that politically set targets, market failures (imperfections, externalities), different maturity levels, systemic failures, adoption processes and the uncertainty about all of these issues make the analysis of energy policy more complicated than suggested by many economic studies that compare different support policy instruments. We started the section by saying that technology-neutral, quantity-control policies (like TGC) are often considered more efficient in economic analyses. However, having reviewed the arguments and conceptually analysed several related issues, we cannot agree with this unconditionally. In contrast, we find that, at least for the economics of early niche development, price-control instruments (which are also reducing most risks for investors) can be equally as and maybe even more efficient than quantity-control instruments. But this also depends on the definition of efficiency and political interests (e.g. if equity is an issue).

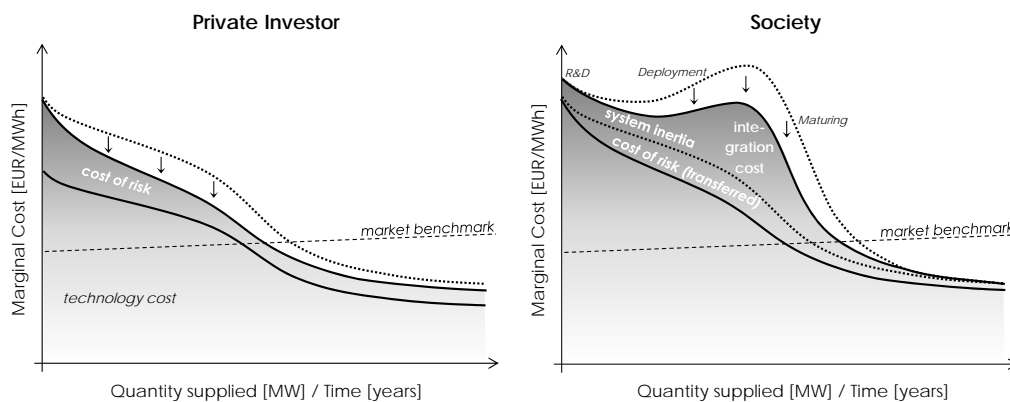


### G.3.4 Reduction of non-market risks and societal costs

In addition to the market risks discussed above, which are often the subject of economic analyses, there are a number of non-market risks that affect investment decisions and which need to be considered in policy evaluation. Many of these risks can be influenced by policy makers. Typical non-market risks are related to policy stability and predictability, permitting procedures, public acceptance issues, etc. The interesting thing about reducing non-market risks is that it reduces costs for private investors without transferring much risk to society. Many of these private non-market risks are either of no concern from a societal perspective or relate to overall inefficiencies to which society is exposed to as a whole (e.g. the delayed connection of a wind park). This means that reducing non-market risks can result in an overall cost reduction.

Weber and Rohrer (2012) argue that ‘policy coordination failure’ can lead to inefficiencies in transition processes, referring both to niche policies (e.g. support of technologies), sectoral policies (e.g. energy market regulation) and cross-cutting policies (e.g. taxation). Concrete policy actions and initiatives need to be coordinated so that the necessary goal-oriented transformative changes can be achieved. Taking this argument further, we argue that such coordinated management can also decrease overall costs. For example, the introduction of smart grid infrastructure and demand-side management technology is beneficial for an improved electricity market operation anyhow (Riesz et al., 2013). If timed in a smart way to support the integration of variable renewable technologies, the overall social cost of both developments can be minimised.

Building further on the economic arguments laid out in Section G.3.3, Figure G.7 conceptually illustrates these overall cost reductions on societal level.



**Figure G.7:** Absolute cost reductions are possible on societal level through reducing non-market risks

In other words, as analysed above, reducing risk increases the effectiveness of a policy to society over the long term; and it also has advantages regarding the dynamic efficiency of an energy transition.

Summing up our analysis until now, we find that scholars promoting the use of technology-neutral, competitive policies, in which new technologies are exposed to significant market risk right from the start of their development, base their analysis mostly on static considerations and do not take specific characteristics of the different transition phases into account. Also, they do not recognise re-allocation of welfare from consumers to producers as an issue, although it is consumers who ultimately have to pay for the (temporarily) additional cost of an energy transition.

## G.4 Policy implications for the transition phases

In this section, we use the conclusions from our above considerations to describe some policy implications for the two phases (see Section G.2.1 for the definition of our transition phases). In the first phase of an energy transition, policy makers create protected spaces to help new technologies grow. Here, fast deployment of the new technologies and the initiation of a dynamic transition process are crucial for a successful transition. In the second phase of the transition, the new technologies become a fully-fledged part of the regime. The policies applied in the previous phase need to be adapted to cope with the new aims of this phase. A more holistic approach is required.

Table G.1 illustrates the potential success criteria that policy makers might have in the first and second transition phase. It adds some potentially successful strategies which we have identified from the above analysis. All elements are discussed in detail below.

### G.4.1 Initiation and control of a dynamic transition process

In the first phase, the transition process is not yet dynamic or self-sustained. Development still depends mostly on political initiative and support schemes. Here, policies should be designed to remove entry barriers through tackling non-market issues (e.g. simplified permitting procedures), and also market issues (e.g. price stabilisation and dispatch priority to reduce perceived and actual risk). The entry of new firms is central to initiating a more dynamic process: New entrants bring additional knowledge, capital, and transfer innovative ideas from other sectors (Jacobsson and Lauber, 2006). More entrants strengthen the ‘political’ position of a niche: their

**Table G.1:** Potential success criteria and successful policy strategies in transition phases 1 and 2

Success criteria	Successful strategies in transition phase 1	Successful strategies in transition phase 2
Dynamic transition process	Initiate dynamic processes: <ul style="list-style-type: none"> <li>- minimise entry barriers and risks</li> <li>- reduce private risks</li> <li>- create an enabling environment</li> </ul>	Control dynamic processes: <ul style="list-style-type: none"> <li>- focus on predictability and stability</li> <li>- introduce policy safeguards</li> <li>- maintain an enabling environment</li> </ul>
Effectiveness (deployment achieved)	Maximum deployment achieved: <ul style="list-style-type: none"> <li>- accelerate growth rate</li> <li>- reduce private cost of risk</li> </ul>	Deployment targets exactly achieved: <ul style="list-style-type: none"> <li>- control growth rate</li> <li>- control support costs</li> <li>- introduce safeguards on price and volume</li> </ul>
Efficiency (cost-effective deployment)	<ul style="list-style-type: none"> <li>- Minimise generation cost</li> <li>- minimise regulator's regret</li> <li>- keep open options of promising immature technologies</li> </ul>	<ul style="list-style-type: none"> <li>- Minimise generation cost</li> <li>- minimise regulator's regret</li> <li>- keep open options of promising immature technologies</li> </ul>
Preparation for phase 2	<ul style="list-style-type: none"> <li>- Coordinated management of related niches</li> <li>- ensure flexibility of the policies to adapt to new challenges</li> </ul>	
Integration of new technologies into regime		<ul style="list-style-type: none"> <li>- Exploit synergies from related niches</li> <li>- empower new technologies</li> <li>- adapt regulations and rules of regime to accommodate new technologies</li> </ul>
Technology cost reduction	<ul style="list-style-type: none"> <li>- Maximise technological learning</li> <li>- accelerate growth rate</li> <li>- introduce modest competitive elements</li> </ul>	<ul style="list-style-type: none"> <li>- Maximise organisational learning</li> <li>- uphold technological learning</li> <li>- introduce more competition</li> </ul>
Public acceptance	<ul style="list-style-type: none"> <li>- Increase equity</li> <li>- minimise support costs</li> </ul>	<ul style="list-style-type: none"> <li>- Increase equity</li> <li>- minimise support costs</li> </ul>
Preparation for discontinuation of policy support		<ul style="list-style-type: none"> <li>- Adapt market rules to provide adequate investment incentives</li> <li>- adapt the support policies for slow phase-out</li> </ul>

opportunity to influence the institutional set-up increases (Jacobsson and Lauber, 2006). A strong and diverse group of firms will develop around the new technologies, and a later adaptation on regime level becomes more likely.

When the energy transition has successfully gone through phase 1, dynamic processes have been initiated that ensure continued technology innovation and market deployment. These often autonomous dynamics can however make the outcomes quite unpredictable (Rotmans et al., 2001). For example, faster than anticipated cost reductions could increase the deployment significantly under FIT schemes (see Section G.3.3). Therefore, often policy makers feel that 'safeguard' need to be employed in policy instruments to retain some control over the process (Finon and Perez, 2007), because of effectiveness and efficiency concerns.

While policies most certainly should be adapted to the changing needs of the different transition phases, it is crucial that policy makers have a prepared and predictable way forward for policy changes. The dynamic processes should be controlled and guided in a certain direction but not completely stopped. Agnolucci (2008) shows that it is in the best interests of consumers and governments to reduce risks related to regulatory and policy changes.

#### **G.4.2 Effectiveness (Deployment achieved) and public acceptance**

In transition phase 1, generally those policies that deliver the highest deployment rates are considered most effective (see Section G.3.2). Rapid growth is required in an early phase for new technologies to ‘take-off’ and set in motion a chain reaction of powerful positive feedback loops (Jacobsson and Lauber, 2006). As discussed above, the reduction of private risks, both market and non-market risks, can lead to accelerated growth. Policies that focus on reducing risks perform thus better under this success criterion.

However, there is empirical evidence that with increasing shares of renewables, policy makers start to be concerned about total support costs (del Río and Cerdá, 2014). Therefore, the success criteria for transition policies might change during the transition from a situation in which overachieving of targets is desirable (maximum deployment is effective) to a situation in which under- or overachievement of targets shall be avoided (exact target achievement is effective). Driving factors for this change in target setting can be ensuring continued public acceptance, stabilising the use of state budget, and ensuring that renewables and regime can develop alongside each other in a timely manner (e.g. to provide sufficient time for large infrastructure reinforcements, changes in market rules, etc.). While these are legitimate concerns, an overly strong focus on minimising support costs might exaggerate the ‘burden’ of support payments for today’s citizens and neglect inter-generational equity problems (Lauber and Jacobsson, 2013).

To ensure that the targeted deployment is exactly achieved, several control mechanisms, or safeguards, can be established. Miller et al. (2013) speak of introducing ‘cost aware’ policies. For FIT schemes, these could include: (1) Regular, predictable adjustment of tariff levels; (2) introducing a total cap on support payments (in monetary terms) or maximum supported amount (in capacity); (3) introducing other quantity-control elements, such as auctioning out of support, as seems to be suggested by the European Commission (2013). In TGC schemes, a quantity-control is already established. However, the total support costs are not minimised. With a uniform certificate price, the cheapest technologies will receive much higher support than required (see Figure G.5). The significance of this issue depends on the energy mix and resource availability of a specific country, but if the deployment targets

are ambitious, often a diverse set of renewable technologies is required. In order to limit support costs and increase public acceptance of TGC schemes, policy makers can minimise total support cost by introducing ‘banding’, a differentiation in the number of certificates the different technologies receive.

### **G.4.3 Efficiency (cost-effective deployment)**

Transition phase 1 is characterised by high barriers and transaction costs for new technologies as well as high uncertainties about current and future costs and benefits. The level of protection against competition and market risks needs to be relatively high to overcome initial inertia, barriers, and uncertainties. Equipment manufacturers, project developers, investors, financing partners, etc. need yet to go through a learning process. Even small risks can be prohibitive for new entrants and for project investments because of the high risk perception. Risks are priced at high premiums. This might lead to inefficient developments, as private choices do not match societal interests any more. In such environment, ‘high risk’ policies and competitive market forces are less effective in providing high deployment rates at minimum costs for society (see Section G.3.2). Protection from overly strong competition and reduction of risk can lead to success until the first major barriers are overcome and market forces become more applicable. The principle of minimising regulator’s regret suggests that price-control instruments may be more appropriate in this phase (see Section G.3.3).

Barriers become less important in transition phase 2, when substantial private and institutional learning has occurred and risks are better anticipated and can be better dealt with. Miller et al. (2013) speak of “changing investment environments” from declining capital costs. Competitive market forces are now more likely to lead to efficient outcomes. A quantity-control element in policies might in this phase become important to minimise the regulator’s regret (see Section G.3.3). Because renewable technologies have now reached a significant market share, not only total support costs become significant, but also the integration cost. In order to minimise these, renewable producers must become better integrated into the regime (Riesz et al., 2013).

### **G.4.4 Preparation for phase 2 and integration of new technologies into the regime**

With an increasing market share of variable renewable technologies, two issues will become important (1) securing grid infrastructure, (2) enhancing system flexibility (see Riesz et al., 2013). To ensure a smooth and successful transition, these issues should be dealt with as early as possible in the process. Grid infrastructure projects

may be required. Their development takes very long time: challenges such as planning and coordination, securing rights of way, public acceptance, allocating costs and more need to be overcome (Miller et al., 2013).

To fully utilise the energy produced from variable renewable energies, system flexibility becomes crucial to minimise curtailments, supply shortages, and system stability (see also Miller et al., 2013). The technologies required for delivering additional flexibility are typically not being developed in the conventional energy system, where they are not demanded. Supporting niches must be initiated early in phase 1 and nurtured, so that appropriate supporting technologies can develop and mature, such as innovative storage options, demand-side management technologies, automated demand response, etc. With a successfully coordinated management of related niches during transition phase 1, the newly matured technologies can be exploited in phase 2. However, the usefulness of the new technologies in regards to the energy transition will depend on how they are supplemented with changes in market design and regulation on regime level (i.e. price signals to consumers, faster market operation and shorter gate closure time, participation on balancing markets, etc.; see Riesz et al., 2013).

We know from empirical evidence that high shares of variable renewable energies can have significant influence on market prices (Klinge Jacobsen and Zvingilaite, 2010). After they have overcome the first phase of learning, RES-E producers have to be prepared to become a ‘normal’ market player with the same responsibilities as every other power producer in the regime. ‘Market aware’ policies are necessary for the power markets to continue to operate efficiently also with high shares of RES-E (Miller et al., 2013, p.8). More concretely, this can be (1) being part of the balancing process; and (2) incentivising reaction to market signals.

Following the concept of risk reduction, RES-E have in the early stages of development been exempted from balancing requirements. After the energy system has successfully moved from transition phase 1 to phase 2 (all three conditions laid out in Section G.2.1 must be fulfilled), it can be beneficial to bring RES-E producers closer to the market by including them in the balancing process. Under FIT schemes, this can e.g. be done through modifying the price guarantee to be based on sliding premiums (or ‘target price FIT’, see Kitzing et al., 2012). The higher risk involved with the additional responsibility does however entail costs for RES-E producers, so the support levels need to be adjusted accordingly. Another option would be to switch the support instrument from a traditional FIT scheme to a FIP. In this situation, it is crucial that the demand of more market integration of RES-E occurs with complementary changes in market design (e.g. shorter times to gate closure etc.), so that new barriers and unexpected exposures can be avoided (Bauknecht et al., 2013). Several countries in the European Union have introduced FIP schemes in the past decade (Kitzing et al., 2012), although this in our opinion might have been done too early, because most countries were still in transition phase 1 and necessary

adjustments in market operations were lacking.

The second issue is related to reaction to market signals. Traditional FIT schemes grant a price guarantee that shields RES-E producers from market signals, so that they sometimes experience production incentives which are not socially optimal: whenever market prices are below the marginal production cost of the respective RES-E technology, it would be beneficial to stop production. With a guaranteed price, producers however have no incentive for to do so (Andor et al., 2012). With an increasing share of RES-E in the system, this issue worsens and significant net social welfare losses could be incurred. In transition phase 2, it may therefore be beneficial to expose RES-E to more market signals. This can be done by small adjustments in the FIT, e.g. through excluding production from support payments at times where market prices are below zero (as in Denmark for offshore wind; DEA, 2009), but also with more radical solutions, such as switching to FIP. Again, this should go hand in hand with respective changes in market design.

#### **G.4.5 Technology cost reduction**

In the early stages of technology development, the technology is still immature and rapid technological learning is required to bring down costs. A focus on technical improvements can be desirable in the first transition phase to accelerate technological learning and create an environment of technical leadership in a country (see Section G.2.3). Attention needs to be directed towards overcoming initial barriers and developing working systems. Overly strong competitive forces can be destructive for this. Risk reduction can help to re-direct efforts from ‘organisational’ learning towards technological progress. As discussed earlier, FIT schemes have generally the most risk reducing characteristics. But also TGC schemes can be adapted to remove some competitive risks, e.g. by differentiating support for different technologies (banding), and establishing price floors. However, the benefit of reducing risk in terms of cost reductions can only be temporary, as in the long run, competitive incentives are necessary to ensure market efficiency. Also, benefits from technological leadership, e.g. in form of increased technology export, will decrease with the maturing of the technology and its worldwide deployment. In transition phase 2, more competitive elements can and should be slowly introduced, thus bringing the different RES-E technologies and projects into competition with each other; and RES-E producers should be exposed to market signals, as discussed above.

### G.4.6 Preparation for discontinuation of policy support

Towards the end of phase 2, the energy transition will reach a point, at which the new technologies are (part of) the new ‘normal’ on regime level. It becomes crucial that the regime is adjusted so that the technologies can develop on a self-sustained basis. No support policy should be needed forever. Which instruments are better in terms of exit strategies has not yet been subject to much research.

Conceptually, we would expect that FIT schemes can rather easily be adapted by slowly reducing the support level until the guaranteed price has reached the market price. Then, RES-E producers will voluntarily opt out of the support. This is not the case with FIP or TGC schemes, where no producer will voluntarily give up an add-on to the market price. Here, the policy makers will have to forecast the market price developments and anticipate at which time the premium can be stepped down to zero, or the certificate market can be closed for new projects. Another complicating issue in the TGC is that it needs a certain market size with liquid trades to function efficiently. As soon as no new projects will enter the market any more, its size will slowly decrease with the decommissioning of old plants. The price setting in an illiquid market will become more and more problematic. This shows that even in the last stages of an energy transition, new solutions have to be found and policies need to be adapted to cope with new requirements. In general, it would be beneficial for the planning of an energy transition to have the different exit options in mind when selecting the appropriate support instruments, so that a smooth and successful transition without disruptions from unnecessary instrument switches can be ensured.

## G.5 Conclusions

We have provided a broader evaluation framework that goes beyond ‘standard’ cost-benefit policy evaluation of ‘which policy is better’. We have argued that the assessment of RES-E support policy instruments in regards of successful energy transitions depend heavily on the assumptions taken in the economic assessment (e.g. if transaction cost and risk-aversion are considered). It also depends on local conditions: Energy mix, resource availability, technology cost structure, market structures, existing regulation, policy making practices and public opinion all contribute to the weighting of the different policy criteria and affect the success likelihood of the potential policy strategies. We have tried to give a somewhat comprehensive discussion of different perspectives. Although the presented approach adopts a broad perspective, many areas are still excluded, such as the interplay between different sectors of energy (electricity, heat, transport) or the interactions of energy transition policies and other related measures (taxes, emission trading schemes, etc.) or other sectors of society (i.e. health and education).



We have shown that in the first phase of an energy transition a focus on risk reduction for private investors and the creation of an enabling environment for the new technology are successful policy strategies. Considering market risks, we could show that risk reducing policies lead to faster deployment without compromising on efficiency in the early stages of the transition. When considering non-market risks, risk reducing policies and a coordinated management in regards to network and system integration have overall cost benefits. FIT schemes inherently reduce market risk, so they seem to be best suited for the purpose of fast deployment in niches. Also they can rather easily be adapted to cope with changing policy needs. If TGC schemes are chosen by policy makers, they can also be adapted to incorporate significant risk reduction elements. For the second phase of the transition, policy focus changes towards integration and regime adaptation, and the new technologies need to become embedded in a new regime with new market rules and infrastructure. Overall, an avowedly strategic framework approach by policy makers will lead to more success. There should be a clear way forward for technology developers, investors and consumers. Tailoring the policies to the specific needs of each phase will not only make the transition more likely to become reality, it will also reduce overall costs.

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In many countries in Europe and the rest of the world, electricity systems are on the verge of a new era: they are transforming from being CO<sub>2</sub>-intensive and centralised towards becoming sustainable and more integrated. Understanding the effects of energy policy and support instruments on investments, especially in terms of risks, is crucial for developing an adequate policy framework in energy systems with high shares of renewable energies. This dissertation assesses energy policy and especially renewable support instruments with regard to their differences in investment incentives, effectiveness of deploying renewable technologies, cost-efficiency (in terms of required support levels) and welfare economic effects. Focus lies on policy incentives that have significant influence on the risk profile of investments (such as renewable quota systems and fixed feed-in tariffs). It is both qualitatively and quantitatively shown that policy makers cannot neglect risk implications when designing support instruments without compromising either on effectiveness or cost-efficiency. Using concepts from financial theory for investments under uncertainty, tools are provided that help in the design of support policies.

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